Delmarva Revised Update to IRP
November 3, 2008

I. <u>Executive Summary</u>

This document provides the most recent updates to the Integrated Resource Plan (IRP) originally submitted by Delmarva Power and Light (Delmarva or DPL) on December 1, 2006, supplemented on January 8, 2007, later revised and updated on March 5, 2008 (the IRP Update) with additional information provided on May 15, 2008 (the IRP Addenda). This IRP filing (the "Revised IRP Update") specifically provides the following revisions and updated information:

1. Detailed Load Forecast information through 2018;
2. A new Reference Managed Portfolio with expected price and price ranges described through 2018. The Reference Managed Portfolio now includes the following resources:
    a. The Residential and Small Commercial Customer ("RSCI") portion of the State Agency approved contract between Delmarva and Bluewater Wind LLC;
    b. The RSCI customer portion of three land based wind contracts (Synergics Roth Rock Wind Energy LLC, Synergics Eastern Wind Energy LLC, and AES Armenia Mountain Wind LLC).
3. The expected price and price stability effects of incorporating longer term generation assets into the Reference Managed Portfolio.
4. The Reliability plan previously submitted by Delmarva on March 2, 2008 updated and extended through 2018;
5. A set of Plan objectives, measures and action plans, elements of which include:
    a. Implementation of a managed portfolio to meet the EURCSA requirements of reasonable cost and price stability;
    b. A plan for meeting all NERC, PJM and Delaware electric system reliability criteria;
    c. Delmarva's plan for securing Renewable Energy Credits derived from on and off-shore wind resources (RECs) and from solar resources (SRECs);
    d. Plans for implementing Demand Response Programs enabled by AMI and other technologies;

e. A process for Delmarva to jointly implement energy efficiency and conservation programs with the Delaware Sustainable Energy Utility (SEU).

Overview of Delmarva

Delmarva is a regulated transmission and distribution utility operating in portions of Delaware and Maryland. Delmarva is engaged in the transmission, distribution and default supply (Standard Offer Service or "SOS") of electricity. In Delaware, Delmarva provides electricity service in the Counties of New Castle, Kent, and Sussex. Delmarva also supplies and distributes natural gas to retail customers in New Castle County and provides transportation–only services to customers that purchase natural gas from other suppliers. This IRP is only applicable to the Delaware electric portion of Delmarva's business.

Delmarva's total electricity distribution service territory covers approximately 6,000 square miles and has a population of approximately 1.3 million in both Delaware and Maryland. As of December 31, 2007, Delmarva delivered electricity to 298,000 customers in Delaware. In 2007, Delmarva delivered a total of 9,004,604 megawatt hours of electricity to distribution customers in Delaware, of which 34% was delivered to residential customers, 40% to commercial customers and 26% to industrial customers.

Load Forecast

PJM prepared a ten year peak demand forecast for the DPL Zone which was published in its 2008 Load Report in December, 2007. This forecast is taken as the Baseline Peak Load Forecast for the zone. This forecast projects an average annual compound growth rate of 1.9% over the forecast period 2008 - 2023. It should be noted that this forecast preceded the recent economic downturn which may well result in lower demand, especially in the near term. PJM is anticipated to update its forecast by the end of the first quarter of 2009.

To determine the jurisdiction and class peak, Delmarva used current Peak Load Contributions ("PLC") to allocate peak and energy requirements by jurisdiction and customer class.

The Baseline Energy Forecast for DPL Delaware is based upon the Company's 2008 Budget and Planning forecast prepared in the Fall of 2007. As with the PJM forecast, this forecast preceded the current economic downturn and therefore is likely to be lowered when it is next updated.

Peak demands are allocated to rate classes, RSCI (residential and small commercial) and non-RSCI classes, and to SOS and non-SOS classes according to the ratios observed in the Company's Settlements data for the day and time of the Zonal peak, August 8, 2007 at 5:00 PM.

Baseline Energy Forecast (MWh)

DPL Delaware					
	Res.	**Small Com.**	**Lrg Com.& Ind.**	**St Light**	**Total**
2008	2,949,077	182,873	5,707,135	36,279	8,875,364
2009	2,973,345	184,086	5,744,981	36,243	8,938,655
2010	3,015,256	187,024	5,836,658	36,247	9,075,184
2011	3,058,986	189,995	5,929,387	36,251	9,214,619
2012	3,106,189	193,076	6,025,544	36,252	9,361,061
2013	3,171,445	197,132	6,152,131	36,252	9,556,960
2014	3,227,771	200,633	6,261,396	36,252	9,726,052
2015	3,284,098	204,135	6,370,660	36,252	9,895,144
2016	3,347,980	208,105	6,494,582	36,252	10,086,919
2017	3,413,923	212,204	6,622,502	36,252	10,284,881
2018	3,466,815	215,492	6,725,104	36,252	10,443,662

Baseline Energy Forecast – RSCI (MWh)

DPL DE SOS RSCI Customers				
	Res.	**Small Com.**	**St. Light**	**Total**
2008	2,847,306	160,967	36,279	3,044,552
2009	2,870,737	162,035	36,243	3,069,015
2010	2,911,202	164,620	36,247	3,112,069
2011	2,953,423	167,236	36,251	3,156,910
2012	2,998,997	169,948	36,252	3,205,196
2013	3,062,001	173,518	36,252	3,271,771
2014	3,116,383	176,600	36,252	3,329,235
2015	3,170,766	179,682	36,252	3,386,699
2016	3,232,444	183,177	36,252	3,451,872

2017	3,296,111	186,785	36,252	3,519,147
2018	3,347,178	189,679	36,252	3,573,108

Baseline Peak Forecast (MW)

Summer

	DPL Zone	DPL Delaware				SOS - RSCI		
		Total	Res	Small Com	LC&I	Res	Small Com	Total
2008	4,192	1,858	960	28	869	927	25	952
2009	4,278	1,896	980	28	887	946	25	971
2010	4,360	1,932	999	29	904	964	26	990
2011	4,442	1,968	1,018	30	921	982	26	1,008
2012	4,522	2,004	1,036	30	938	1,000	26	1,027
2013	4,617	2,046	1,058	31	958	1,021	27	1,048
2014	4,699	2,082	1,076	31	975	1,039	27	1,067
2015	4,781	2,119	1,095	32	992	1,057	28	1,085
2016	4,874	2,160	1,116	32	1,011	1,078	29	1,106
2017	4,970	2,202	1,138	33	1,031	1,099	29	1,128
2018	5,047	2,236	1,156	34	1,047	1,116	30	1,146

Winter

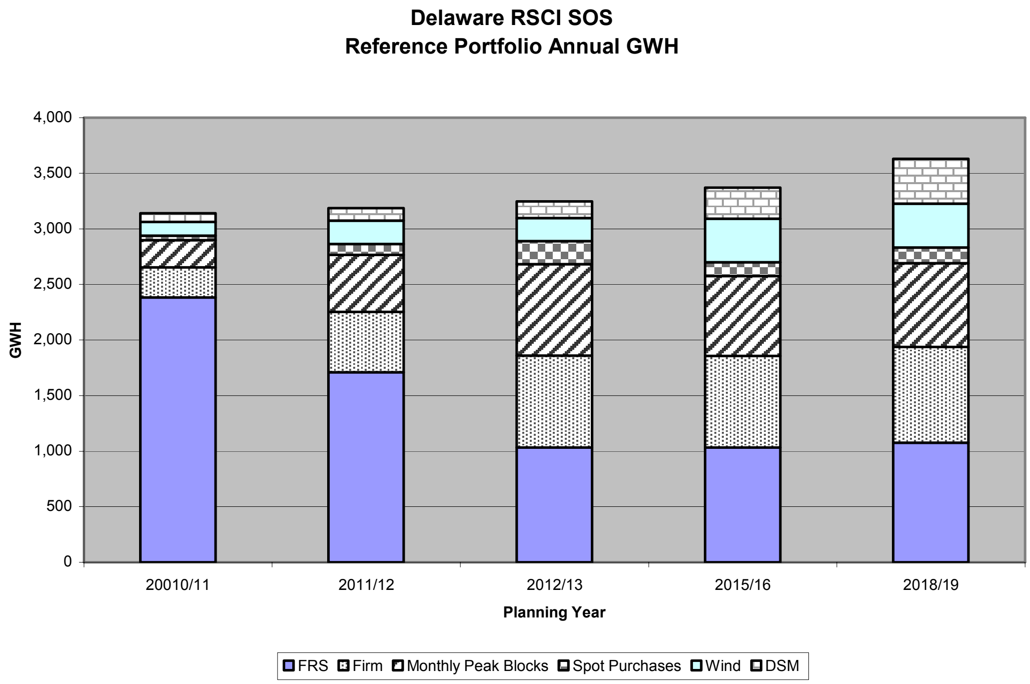
	DPL Zone	DPL DE
2008/9	3,442	1,462
2009/10	3,497	1,486
2010/11	3,547	1,507
2011/12	3,598	1,529
2012/13	3,642	1,547
2013/14	3,685	1,566
2014/15	3,743	1,590
2015/16	3,798	1,614
2016/17	3,857	1,639
2017/18	3,908	1,660

(Note: All Table Totals reflect rounding)

Managed Portfolio.

The managed portfolio presented in the May 15, 2008 IRP Addenda examined the planning period 2008 – 2016. The chart below provides the expected reference portfolio composition for

Delmarva's SOS RSCI customers through 2018 and includes the contribution of the approved land based and off-shore wind resources in the portfolio.



Previous submittals in this Docket have provided a discussion of the theory and risk management objectives of portfolio management[1]. The table and figures below provide the expected mean and range of outcomes for the Reference portfolio for selected years in the planning period as well as the same information for several potential long-term stabilization scenarios around the Reference portfolio, including the simulated effects of adding either a regulated 100 Mw combustion turbine or a 100 MW power purchase agreement with a combined cycle unit.[2] The results of these analyses are also provided in the table and figures below.

[1] Recent events in financial markets indicate that there may be significant exposure to collateral requirements for parties engaged in portfolio procurement. This is an issue that Delmarva plans to discuss further in the Portfolio Working Group, including the recovery of any costs for collateral requirements imposed on Delmarva.

[2] Due to time and resource considerations, an economic recession scenario was not evaluated in this update to the IRP. At this point in time, it may be somewhat early to determine what the likely longer term impacts of the current economic situation may be, not only for Delmarva, but also for the PJM region. Nevertheless, an economic recession could have significant implications for Delmarva's long term planning requirements.

In the table and figures the following statistics are provided for each portfolio: the expected Total average Cost in $/MWH of the portfolio in that year, the "Low Average Cost" which indicates that 10% of the outcomes of the simulation analyses were below this level, the "High Average Cost" which indicates that 90% of the outcomes of the simulation analyses were below this level (and 10% were above), and the Average Cost of all simulated results that were above the High Average 90% cost.

Figure 1: Average Costs and Risks of Electricity Procurement for DPL as Expected in August 2008

Planning Year 2010

	Total Average Costs ($/MWh)	Low Average Costs 10.0% ($/MWh)	High Average Costs 90.0% ($/MWh)	Difference between High and Low Costs ($/MWh)	Difference as Percent of Average	Average Costs Above 90% ($/MWh)
100% Open	$107.81	$78.64	$141.16	$62.52	57.99%	$158.88
Reference Case	$115.53	$106.52	$125.42	$18.90	16.36%	$129.88
Reference Case and CC PPA	$116.82	$109.32	$125.21	$15.89	13.60%	$129.26
Reference Case and Regulated CT	$117.64	$109.19	$126.99	$17.80	15.13%	$131.02

Planning Year 2011

	Total Average Costs ($/MWh)	Low Average Costs 10.0% ($/MWh)	High Average Costs 90.0% ($/MWh)	Difference between High and Low Costs ($/MWh)	Difference as Percent of Average	Average Costs Above 90% ($/MWh)
Reference Case	$119.06	$103.15	$136.36	$33.21	27.90%	$143.90
Reference Case and CC PPA	$119.05	$105.50	$133.14	$27.64	23.21%	$139.39
Reference Case and Regulated CT	$119.96	$104.73	$136.55	$31.82	26.52%	$142.96

Planning Year 2012

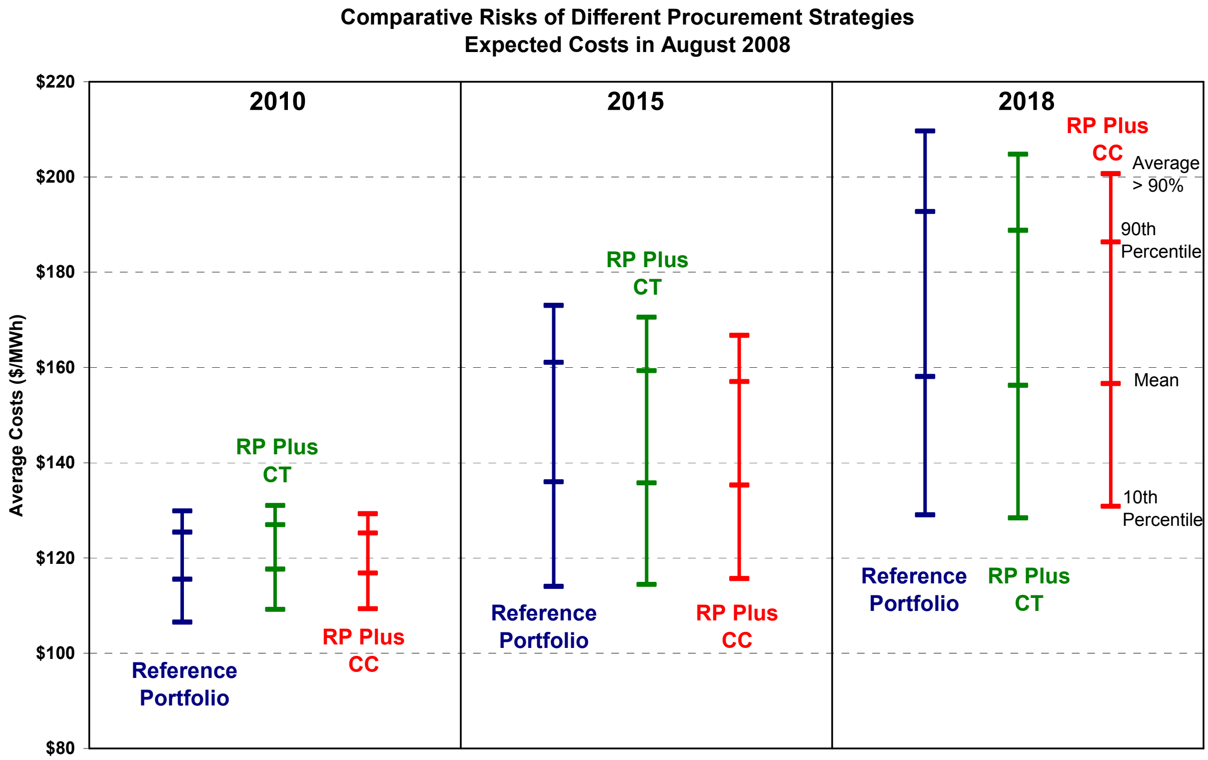
	Total Average Costs ($/MWh)	Low Average Costs 10.0% ($/MWh)	High Average Costs 90.0% ($/MWh)	Difference between High and Low Costs ($/MWh)	Difference as Percent of Average	Average Costs Above 90% ($/MWh)
Reference Case	$136.95	$120.33	$156.01	$35.68	26.05%	$164.68
Reference Case and CC PPA	$133.56	$119.43	$148.91	$29.48	22.07%	$155.32
Reference Case and Regulated CT	$134.59	$118.75	$152.29	$33.54	24.92%	$159.66

Planning Year 2015

	Total Average Costs ($/MWh)	Low Average Costs 10.0% ($/MWh)	High Average Costs 90.0% ($/MWh)	Difference between High and Low Costs ($/MWh)	Difference as Percent of Average	Average Costs Above 90% ($/MWh)
Reference Case	$135.96	$114.00	$161.06	$47.06	34.61%	$173.05
Reference Case and CC PPA	$135.27	$115.69	$157.02	$41.33	30.55%	$166.71
Reference Case and Regulated CT	$135.76	$114.41	$159.32	$44.91	33.08%	$170.53

Planning Year 2018

	Total Average Costs ($/MWh)	Low Average Costs 10.0% ($/MWh)	High Average Costs 90.0% ($/MWh)	Difference between High and Low Costs ($/MWh)	Difference as Percent of Average	Average Costs Above 90% ($/MWh)
Reference Case	$158.11	$129.06	$192.76	$63.70	40.29%	$209.66
Reference Case and CC PPA	$156.62	$130.84	$186.38	$55.54	35.46%	$200.69
Reference Case and Regulated CT	$156.27	$128.39	$188.79	$60.39	38.65%	$204.81



The table and figures show several things: First, the reference portfolio and various generation alternatives have about the same average cost over the planning period. Second, over time there are wider ranges of possible future average annual costs. Third, adding 100 MW of gas generation to the portfolio would slightly raise average costs in 2010 and would slightly lower them by 2018. However, these results describe generic CTs and CCs. Expected costs and locational benefits at actual potential sites in Delaware would have to be evaluated to determine if there would be meaningful benefits to a specific resource.

Finally, recent events make it more difficult to be confident of the expected value of forecasts in general. Load growth, commodity prices, capacity expansion, risk premiums, and the costs of financing (or collateralizing long term contracts) may well be affected. The net impact will not necessarily be to make future power less expensive than the projections herein, even though recent energy forward prices have declined. Risk management goals and policies may now become even more important.

Delmarva respectfully submits that the Reference portfolio provides both reasonable cost and price stability as required by EURCSA, while also meeting the Delaware RPS requirements. Delmarva also noted in the March 5, 2008 and May 15, 2008 submittals in this Docket that the implementation of a managed portfolio for the procurement of the electrical requirements of RSCI SOS customers will necessitate the approval of cost recovery mechanisms associated with the implementation and operation of the managed portfolio. In the May 15, 2008 submittal in this Docket, Delmarva provided specific proposals for such cost recovery mechanisms and Delmarva continues to recommend adoption of these proposals prior to implementation of the managed portfolio. A copy of these proposals is provided in Appendix D.

It is also important to note that the results relating to long-term resources are sensitive to underlying cost and operating assumptions and that the long term generation resources evaluated herein are generic representations of these resources; they do not represent specific offers for actual sites and facilities that may be available to Delmarva. Similar to the recommendations of the May 15 submittal, Delmarva recommends that the Commission allow Delmarva to conduct a market test to obtain current market information regarding the pricing of 5, 10 and 15 year contracts for firm energy and capacity for potential inclusion in the RSCI SOS procurement portfolio. Additionally if the Commission finds that regulated generation is in the public interest, then Delmarva should be authorized to conduct a generation site feasibility study to review potential sites, costs, licensing and site specific infrastructure requirements.

Reliability

PHI/Delmarva has made significant progress towards meeting the projected in service date for the MAPP project. Initial design, siting, environmental and community outreach activities have begun. PHI expects to file a Certificate of Public Convenience and Necessity ("CPCN") application for the southern Maryland portion of the line by first quarter of 2009. PHI has worked with PJM to evaluate various technology options for crossing the Chesapeake Bay. At the October 15, 2008 Transmission Expansion Advisory Committee

(TEAC) meeting PJM recommended that DC technology be used for the crossing of the Chesapeake Bay. This will increase transfer capability, allow greater controllability of flow on the line and have a smaller footprint in the Chesapeake Bay. The Company recently introduced a separate web site for the MAPP project at www.powerpathway.com. This web site will be an important link for stakeholders going forward and a location where questions will be answered and updates posted.

Delmarva expects that over the planning period the combination of generation internal to the DPL Zone and the capability of the transmission system to import power from outside the Zone will exceed the PJM transmission transfer objectives established to meet the regional reliability margins for the Zone. Delmarva also has developed preliminary plans for transmission system enhancements that may be needed in the event of generation unit retirements during the planning period.

Plan Objectives, Measures and Action Plans

A significant update to this IRP is the specification of Plan objectives, measures and actions plans by which the Plan's progress can be assessed over time. Going forward, Delmarva's plan is structured around key objectives related to: I)Reasonable Cost and Price Stability; II) Reliability; III) Renewable Resources; IV) Demand Response; and V) Energy Efficiency. These are more fully described below:

I. Reasonable Cost and Price Stability:

Objectives:

a. Evaluate generation, transmission and demand side resource options during the planning period to ensure that sufficient and reliable resources to meet customer needs are acquired at a reasonable cost.
b. Provide year over year price stability in the quarterly prices paid by RSCI SOS customers for their total electricity supply.

Measures:

a. Obtain Commission acknowledgement that the IRP does not appear to be unreasonable in meeting these objectives.

b. Provide a quarterly report comparing :

   i. Actual portfolio performance for the current quarter with the previous quarter and the same quarter from the previous year.

   ii. Actual portfolio performance with the annual portfolio expectation.

Action Plan:

a. In accordance with EURCSA, the Company will prepare and file an Integrated Resource Plan at least once every two years. The IRP will include a systematic evaluation of generation, transmission, and demand side resource options. Under this schedule, Delmarva will file the next IRP on or before December 1, 2010.

b. The IRP will provide an evaluation of various resource mixes showing both the expected outcome in terms of average price and the potential range of outcomes around the expected price.

c. Pending timely approvals as appropriate, the Company will implement a managed portfolio approach to procuring RSCI SOS customer supply requirements according to the following schedule:

   1) Begin serving a portion of the RSCI SOS load using a managed portfolio approach beginning June 1, 2010.

   2) Target 66% of the RSCI SOS load served using a managed portfolio approach by June 1, 2012 (with approximately 33% of the RSCI SOS customer load requirements obtained through the existing RFP process).

d. Create a Portfolio Working Group tasked with establishing general working and implementation guidelines for managing the SOS RSCI portfolio. These guidelines should be established at least 12 months prior to beginning procurement through the managed portfolio and should specify all relevant reporting and monitoring requirements.

e. Obtain approvals, as needed, to effectuate the cost recovery proposals outlined in the Company's IRP Addenda of May 15, 2008 to enable the timely implementation of the managed portfolio to procure SOS RSCI customer supply[3].

II. <u>Reliability</u>:

Objective:

Ensure that the electric system serving Delmarva's customers meets all NERC, PJM, and Delaware Commission transmission electrical reliability requirements.

Measures:

a. Schedule for completing PJM approved zonal RTEP projects as listed on the "RTEP Construction Status" page on the PJM Website (www.pjm.com).

b. Reliability standards in DE PSC Docket 50 "Electric Service Reliability and Quality Standards." From Section 4 of that document, transmission "Reliability and Quality Performance Benchmarks" include:

i. Transmission CAIDI & SAIDI (excluding major events) as part of the overall system CAIDI and SAIDI

ii. Constrained hours of operation

Action Plan:

a. Complete all approved PJM RTEP Delmarva Zone projects by required in-service dates.

b. Provide updates for annual Docket 50 transmission standards targets (in "Reliability Planning and Studies Report" - submitted annually in March for the current calendar year) and performance (in "Reliability Performance Report" - submitted annually in April for the previous calendar year).

[3] A copy of these cost recovery proposals is provided as Appendix D.

III. Renewable Energy:

Objectives:

a. Obtain Renewable Energy Credits (RECs) and Solar Renewable Energy Credits (SRECs) through a diverse renewable resource portfolio at a reasonable cost

b. Obtain RECs from land based and off-shore wind energy resources over the planning period sufficient to meet the requirements of the SOS RSCI customers as identified by the State of Delaware Renewable Energy Portfolio Standards (RPS).

c. Obtain sufficient SRECs to satisfy the SOS RSCI customer load requirements as identified by the State of Delaware Renewable Energy Portfolio Standards (RPS).

Measure:

Verify that annual RPS requirements for SOS RSCI customers are met through existing contracts with wind generators and that required solar resources are either acquired through Company owned facilities, the SEU, or the market as needed.

Action Plan :

1. Begin receiving energy and REC's as part of the SOS RSCI customer portfolio from the following executed and approved contracts from wind generators according to the following schedule[4]:
    a. AES Armenia Mountain Wind: 70 MW wind facility located in central Pennsylvania with a guaranteed initial delivery date of April 30, 2010;
    b. Synergics Roth Rock Wind Energy: 40 MW wind facility located in Western Maryland with a guaranteed initial delivery date of December 31, 2009; and,

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[4] Delmarva may begin receiving service from these facilities earlier than the guaranteed initial delivery dates if the facilities begin commercial operation prior to their respective guaranteed initial delivery dates.

c. Synergics Eastern Wind Energy: 60 MW wind facility located in Western Maryland with a guaranteed initial delivery date of December 31, 2010.

d. Bluewater Wind 200MW from an off-shore wind facility to be constructed 11 miles of the coast of Delaware at Rehoboth Beach. The guaranteed initial delivery date of December 1,2014

2. Obtain the RECs associated with solar photovoltaic resources sufficient to meet the Delaware RPS:

a. Obtain additional Solar RECs as needed through the market either as part of the SOS RFP process or through a separate product.

b. In coordination with the Delaware SEU, establish a process to procure solar REC's for SOS RSCI customers on a timely basis through the SEU. The target date for completing Delmarva's arrangement with the SEU and submitting for Commission approval is the 2nd Quarter of 2009.

c. Explore utility owned solar resources**.**

IV. <u>Demand Response</u>:

Objective:

Implement cost effective demand response programs with a focus on those programs enabled by the "smart grid" and the associated deployment of Advanced Meter Infrastructure (AMI) in Delaware.

Measure:

Peak MWs saved as a result of demand response programs.

Action Plan:

1. Work with the Demand Response Working Group to develop a schedule for implementing a Demand Response program. The schedule should include the following elements:

a. AMI deployment:

b. Internet Portal implementation

c. Residential Direct Load Control Program Plan implementation

d. Small Commercial Direct Load Control Program implementation

e. Dynamic Pricing Program (for SOS Customers) implementation

V. Energy Efficiency:

Objective:

Co-ordinate the implementation of cost-effective energy efficiency programs with the State of Delaware Sustainable Energy Utility as appropriate or as directed by the Commission.

Measures:

a. Energy Efficiency program specifications developed with SEU

b. Customer MWh use reductions as agreed to with the SEU in program specifications.

Action Plan:

Complete the following tasks:

a. File Program Plan w/Commission

b. Conduct Annual Review of Programs w/SEU

II. BACKGROUND

Under the requirements of the Electric Utility Retail Customer Supply Act of 2006 ("EURCSA" or "HB 6") and as part of Delaware Public Service Commission (the "Commission") Docket No 07-20, Delmarva Power & Light ("DPL", "Delmarva", or the "Company") filed an Integrated Resource Plan ("IRP") with the Commission on December 1, 2006. EURCSA also requires Delmarva to file an IRP every other year thereafter. On December 13, 2006, Staff requested additional information related to the IRP filed on December 1, 2006[5]. On January 8, 2007, the Company filed a 71 page report providing the detailed supporting documentation requested by Staff[6]. This supporting information should be considered as part of the IRP filed December 1, 2006.

Delmarva's December 1, 2006 IRP results, based on a detailed resource planning model and Demand Side Management ("DSM") program evaluations, concluded that: 1) the least cost plan would require no new generation to be sited in Delaware to meet the electrical needs of Standard Offer Service ("SOS") customers over the planning period, other than a modest amount of renewable energy (30-40MW); 2) investments in transmission facilities were the most appropriate way to maintain system reliability needs over the planning period; 3) the Company should implement the many cost-effective Energy Efficiency and Demand Response programs identified in the plan; and 4) obtaining Full Requirement Service (FRS) contracts for SOS procurement should be continued.

Although the IRP filed December 1, 2006 did not indicate the need for the Company to enter into long term Power Purchase Agreements ("PPAs") for new generation to be located in Delaware, it was noted within the IRP that the Company intended to update the results of the resource plan and SOS procurement strategies as needed upon such time as the Commission

[5] Delmarva Power and Light Integrated Resource Plan, 2007 – 2016, Compliance Filing, PSC Docket 06-241, December1, 2006
[6] Delmarva Power and Light Integrated Resource Plan, 2007 – 2016, Supplemental Data, PSC Docket 06-241, January 8, 2007

and the State Agencies concluded their then on-going evaluation of the proposals received as part of the Generation Request for Proposal ("RFP") process[7].

Comments on the December 1, IRP and the supporting documentation were filed in early March 2007 by intervening parties[8]. On March 23, 2007, Delmarva filed comments in response to the intervening parties' comments.[9]

On April 4, 2007, the Independent Consultant ("IC") filed a report on the Delmarva Power IRP in relation to the RFP.[10] On May 3, 2007, the Company filed comments in response to the IC's report.[11]

Delmarva notes that at the time of the December 1, 2006 IRP filing, wherein Delmarva suggested filing an updated IRP that included the results of the State Agencies decision regarding the RFP bidding process, it was expected that the State Agencies' evaluation of the bids received in response to the RFP process would be completed on the then existing schedule. However, due to the duration of the RFP process, the deadline for filing an IRP to include the results of that process was extended. The last such deadline extension to prepare and file an updated IRP, granted by Hearing Examiner Price, was March 5, 2008.

On March 5, 2008 Delmarva filed an Update to the IRP[12] (the "Update"). Although at the time the Update was filed no decision had been reached by the State Agencies on the outstanding RFP bids, a number of significant events had occurred in Delaware specifically affecting the IRP. One of these significant events was Commission Order No 7199 in Docket No. 07-20 issued May 22, 2007. Among other items, this order directed the Company to procure the electrical energy needs of SOS customers through an actively managed portfolio.

The requirement to actively manage a resource portfolio for SOS procurement was a significant departure from the Company's recommendation in the December 1, 2006 IRP. Thus,

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[7] See IRP pp 3. At the time of the IRP filing on December 1, 2006, the bids from the RFP process had not yet been received and consequently, specific cost and other data relevant to each of the proposed projects was not yet available for evaluation purposes.
[8] See March 7 – 13, 2007 Comments on IRP Filing, PSC Web Site
[9] Response to Comments on Delmarva's Integrated Resources Plan ("IRP"), filed December 1, 2006.
[10] Interim Report on Delmarva Power IRP in Relation to RFP, April, 4, 2007
[11] Delmarva's Comment on the independent Consultant's Report, May 3, 2007
[12] Delmarva Power & Light Company's Delaware IRP Update, March 5, 2008

in the March 5 Update, the Company described in some detail a risk management framework to guide the portfolio management process.[13] The Update also respectfully requested the creation of a collaborative Working Group with Staff and the Delaware Public Advocate (DPA) to facilitate the development of the "rules of the road" under which a portfolio for Delmarva SOS electrical procurement would be implemented and managed.

On March 24, 2008, Staff requested additional information from the Company related to the Update. In particular, Staff asked the Company to clarify certain information with regard to compliance with EURCSA and to identify more specific "rules of the road" relating to portfolio management, cost recovery and customer migration that the Company would recommend, as well as the portfolio resources that the Company would expect to procure and manage for each year of the planning period consistent with the rules proposed by the Company.

The May 15 Addenda to the IRP ("Addenda") provided the Company's response to these information requests. In addition, to more clearly indicate how the Company had complied with various requirements of EURCSA, an overview of the SOS procurement portfolio development process was also presented.

On May 21, 2008, Hearing Examiner Ruth Ann Price released a Proposed Procedural Schedule for considering the Addenda, with initial discovery beginning on June 2 and evidentiary hearings in mid-December 2008.

On June 23, 2008 Delmarva and Bluewater Wind (BWW) executed a PPA establishing, among other things, the size of an offshore wind project.

On June 25, 2008 the Delaware General Assembly passed legislation, signed by the Governor later that day, which, among other provisions, provided that the costs rising out of the PPA would be distributed among Delmarva's entire customer base through a non-bypassable surcharge.

As a result of this agreement, on July 3, 2008, the Company, jointly with Intervener Dr. Jeremy Firestone, filed a motion requesting that Hearing Examiner Price suspend the May 21

[13] See pps 78 - 103 of update

procedural schedule pending a Commission decision on whether the remainder of the 2006 IRP should be merged with the IRP due on December 1, 2008.

On July 11 Staff filed its response to the motion, stating that on July 31 the State Agencies would be considering the merits of the Offshore Wind PPA and requesting a 45 day suspension of this docket.

On July 14, 2008 Hearing Examiner Price suspended all matters related to this docket until September 4, 2008.

On July 28, 2008 Delmarva filed an application with the PSC, in Docket No. 08-205, for approval of three contracts providing a total of 170 MW of land-based wind (LBW) energy and renewable energy credits (RECs).

On July 31, 2008, the four State Agencies approved the Delmarva-BWW Offshore Wind PPA.

On September 2, 2008, in Order No. 7440, the Commission approved the Delmarva-BWW PPA and closed Docket No. 06-241. In closing the RFP Docket, the PSC ordered that the potential addition of new generation resources in Southern Delaware would be considered in this IRP Docket.

On September 10, 2008, in Docket 07-20, Hearing Examiner Price issued a revised schedule for IRP review, calling for this new "updated" IRP to be filed on November 3, 2008. The schedule includes public comment sessions in December 2008, workshops for the parties in February and March 2009 and evidentiary hearings in late July 2009.

On October 7, 2008, following evidentiary hearings in Docket No. 08-205, the PSC, in Order No. 7463, approved the three contracts in Delmarva's LBW application.

III. PORTFOLIO ANALYSIS UPDATE

The managed portfolio recommended in Delmarva's May 15, 2008 submittal has been updated to include the recently approved land-based and off-shore wind contracts. The recommended supply portfolio now includes a blend of wholesale contracts of various durations, the existing and ongoing future full-requirements (FR) contracts obtained in RFPs, the recently contracted land-based wind resources (up to 70 MW beginning in 2010 and 2011, of which approximately 70% is dedicated to RSCI SOS customers) and the Bluewater Wind (BWW) offshore project (200MW beginning 2014, of which approximately 35% is dedicated to RSCI SOS customers).

A large part of this portfolio is not yet under contract (just the wind resources and near term FR contracts). The design of the portfolio can be modified to have different components, procurement schedules, and risk characteristics. This portion of the portfolio has the same basic structure as the Managed Portfolio that was proposed in the May 2008 IRP filing by Delmarva. This portfolio consists of a three-year fixed-price forward purchase of firm all-hours power (i.e., a "baseload" purchase) covering approximately 44% of total annual energy requirements, installment purchases at simulated monthly forward prices for on peak power beginning twelve months in advance of delivery (sometimes referred to as "dollar cost averaging" or DCA), and the balance spot purchases. This total portfolio including the wind and FR contracts is referred to as the Reference Portfolio (RP). This design has not been chosen to be the "optimal" mix of contracts, though it matches the load shape of Delmarva's RSCI SOS customers (net of the FR contracts and the expected effects of the Delaware SEU's energy conservation programs). Delmarva has suggested in prior submittals in this Docket that a Portfolio Working Group be created to discuss the pros and cons of alternative risk management strategies for this portion of the RSCI supply portfolio.

An evaluation of how the RP would be affected by adding gas-fired generation, in the form of a combustion turbine or a combined cycle unit partially owned by Delmarva (with costs recovered on a traditional cost-of-service basis, i.e., as a regulated asset) or under purchased power agreements (PPAs) for ten years with a levelized (constant nominal) charge per MWh for fixed-cost recovery and flow-through of fuel costs as incurred is also presented .

This analysis is based on market conditions that obtained at the beginning of August 2008. At that time, in preparation for a similar proceeding in Maryland, PHI and its advisors (ICF International and The Brattle Group) had obtained or developed comprehensive market and forecast information. That same information is utilized in this proceeding because it is still an apt description of long-run conditions, and because current conditions are so unstable that it is difficult to decide how well the markets reflect future conditions. In addition, the primary purpose of this report is to compare the relative attractiveness of different alternatives, not to make a precise forecast of what expected future prices will actually be. The data developed in late summer is appropriate for this purpose.

There is a requirement in Delaware that at least 30% of Delmarva's power should be obtained from competitive wholesale procurements. It is likely that Delmarva will satisfy that requirement with annual RFPs for 3-year contracts for 1/9th of its expected load. In this analysis, those future FR procurements are simulated as though 1/3 of total needs are procured every 3 years. This simplifies the analysis, while still reflecting the cost and risk implications of future competitive procurements.

Delmarva's wind contracts will have energy uncertain output. Accordingly, these contracts are simulated as being added financially to the portfolio, rather than as displacing other purchases in it. The net effect is identical to netting them against RSCI load and then buying for the balance, but this method of simulation (as well as of actual operation) is easier to prepare and to describe.

Dates reported in this analysis refer to PJM planning years, extending from June 1 to May 31 of each calendar year. These planning years are referred to by the calendar year in which they begin; thus "2010" means June 1, 2010 through May 31, 2011. 2010 was selected as the first year of analysis, because that is the earliest date that this portfolio approach could be implemented. The procurement for 2010 would have to begin a half a year or more in advance. In this analysis, June 1, 2009 has been chosen as the simulated date when procurement would begin, and results are presented from the perspective of August 1, 2008, the date of the market forward prices that provide the initial basis for the simulations.

Key Findings

The tables in Figure 1 on the next page present the expected and likely ranges of costs from the simulated portfolios in 2010-2012, 2015, and 2018. The tables present the expected cost per MWh of the RP in each of these years, along with the range of annual average costs foreseen for the 10th and 90th percentiles of simulated possible outcomes. Those ranges are the result of Monte Carlo simulations of 1000 scenarios per year, in which the possible outcomes are drawn from distributions that describe market expectations and volatility as of August 1, 2008.

The predominant character of the RP changes somewhat over time. In 2010, its costs and risks are affected by the fixed price of the existing FR contracts. Thereafter, those contracts will be replaced, but at prices that are today uncertain (hence risky). The farther in the future such procurements will occur, the riskier they become from today's vantage point – simply because there is more time for conditions to change, hence more forecasting error.

Over the next ten years, gas-fired resources owned or under contract to Delmarva would have little effect on the average cost of the RP. This occurs for two reasons. First, market conditions in August 2008 happen to be close to providing a financial breakeven outlook for investments in such plants. Second, gas and electric markets are forecasted to stay in roughly the same relationship to each other over the years of the coming decade. This is in part an assumption, but it is also a result of the fact that gas-fired generation often sets the energy market clearing price in PJM (i.e., it is the marginal resource) and also tends to be the expansion technology of choice (hence strongly influencing PJM capacity prices as well.) However, gas fired generation reduces RP riskiness somewhat, especially a CC if/when CO2 pricing becomes part of U.S. national energy policy. If long-term resources are added to the portfolio, especially under fixed pricing, it may be appropriate to restrict customer switching or implement alternative risk mitigation strategies, so that there is little risk of future stranded assets.[14] The gas resources evaluated herein are entirely generic, not specific to actual sites and facilities that might be available to PHI. It would be essential to conduct further feasibility studies before concluding that local opportunities really have these features.

The pricing of CO2 emissions is a risk in the long term, with the potential to raise PJM prices by a few $/MWh by 2015-2020 and by more thereafter. The wind resources Delmarva has recently obtained provide a hedge against this likely situation. Gas-fired generation of course produces CO2, but less so than coal per MWh, and the low prices for CO2 likely over the next 10 years should not impair the savings available from gas relative to other types of generation.

Very recently, commodity and financial market conditions have shifted rapidly due to the international credit crisis. While this has caused gas and electric futures prices to drop by about 25%, it is not yet clear whether this is an over-reaction or a fundamental shift. It is also unclear whether supply or demand for power will be more affected over the next few years. The most likely implication for resource and portfolio planning is that risk ranges based on historical evidence may prove to be under-estimates.

[14] In the May 15 filing in this docket Delmarva has proposed a "trigger" mechanism to mitigate the risk of customer migration.

Figure 1: Average Costs and Risks of Electricity Procurement for DPL as Expected in August 2008

Planning Year 2010

	Total Average Costs ($/MWh)	Low Average Costs 10.0% ($/MWh)	High Average Costs 90.0% ($/MWh)	Difference between High and Low Costs ($/MWh)	Difference as Percent of Average	Average Costs Above 90% ($/MWh)
100% Open	$107.81	$78.64	$141.16	$62.52	57.99%	$158.88
Reference Case	$115.53	$106.52	$125.42	$18.90	16.36%	$129.88
Reference Case and CC PPA	$116.82	$109.32	$125.21	$15.89	13.60%	$129.26
Reference Case and Regulated CT	$117.64	$109.19	$126.99	$17.80	15.13%	$131.02

Planning Year 2011

	Total Average Costs ($/MWh)	Low Average Costs 10.0% ($/MWh)	High Average Costs 90.0% ($/MWh)	Difference between High and Low Costs ($/MWh)	Difference as Percent of Average	Average Costs Above 90% ($/MWh)
Reference Case	$119.06	$103.15	$136.36	$33.21	27.90%	$143.90
Reference Case and CC PPA	$119.05	$105.50	$133.14	$27.64	23.21%	$139.39
Reference Case and Regulated CT	$119.96	$104.73	$136.55	$31.82	26.52%	$142.96

Planning Year 2012

	Total Average Costs ($/MWh)	Low Average Costs 10.0% ($/MWh)	High Average Costs 90.0% ($/MWh)	Difference between High and Low Costs ($/MWh)	Difference as Percent of Average	Average Costs Above 90% ($/MWh)
Reference Case	$136.95	$120.33	$156.01	$35.68	26.05%	$164.68
Reference Case and CC PPA	$133.56	$119.43	$148.91	$29.48	22.07%	$155.32
Reference Case and Regulated CT	$134.59	$118.75	$152.29	$33.54	24.92%	$159.66

Planning Year 2015

	Total Average Costs ($/MWh)	Low Average Costs 10.0% ($/MWh)	High Average Costs 90.0% ($/MWh)	Difference between High and Low Costs ($/MWh)	Difference as Percent of Average	Average Costs Above 90% ($/MWh)
Reference Case	$135.96	$114.00	$161.06	$47.06	34.61%	$173.05
Reference Case and CC PPA	$135.27	$115.69	$157.02	$41.33	30.55%	$166.71
Reference Case and Regulated CT	$135.76	$114.41	$159.32	$44.91	33.08%	$170.53

Planning Year 2018

	Total Average Costs ($/MWh)	Low Average Costs 10.0% ($/MWh)	High Average Costs 90.0% ($/MWh)	Difference between High and Low Costs ($/MWh)	Difference as Percent of Average	Average Costs Above 90% ($/MWh)
Reference Case	$158.11	$129.06	$192.76	$63.70	40.29%	$209.66
Reference Case and CC PPA	$156.62	$130.84	$186.38	$55.54	35.46%	$200.69
Reference Case and Regulated CT	$156.27	$128.39	$188.79	$60.39	38.65%	$204.81

BACKGROUND ON PORTFOLIO PROCUREMENT AND RISK MANAGEMENT

The RSCI SOS supply portfolio procurement problem facing Delmarva (or any supplier of full-requirements retail service) is a complex one. There are several kinds of uncertainty that must be anticipated, several ways of achieving price stability, and several kinds of constraints on the possible solutions that must be recognized. Key uncertainties include:

- Future load levels and shapes (which in turn depend on how many customers have switched to or from 3d party retail suppliers and other factors like weather),
- Power prices in the wholesale spot and forward markets for energy and capacity,
- Prices of PJM services and obligations, such as ancillary services, congestion, losses and RPM capacity,
- Construction costs and fuel prices, if physical assets are to be part of the portfolio composition.

A first step in portfolio planning is to have market outlooks or forecasts of these factors, as well as measures of their uncertainty, expressed as possible future price ranges along with associated probabilities and the correlations among them.[15] To the extent possible, this information should be taken from the wholesale power and financial markets, rather than from fundamental forecasts, because market prices reflect conditions under which parties will actually trade. However, market price data is only available for one to two years forward, so long term studies are also required for structural forecasts of future prices based on projected scenarios for market conditions. Once these parameters are quantified, they can be used to project possible future costs of alternative supply portfolios across a broad range of market circumstances that could unfold.

In general, the total risk of the SOS supply problem cannot be reduced or eliminated. However, it is possible to control who incurs certain risks along the supply chain -- albeit often at some expense. For instance, load uncertainty is inevitable, but its costs can (for modest time intervals) be made entirely the burden of upstream suppliers in exchange for a risk premium (as in the current full-requirements, vertical tranche RFPs). Alternatively, some risks can be buffered at the utility level (*e.g.,* in a balancing account for capturing and eventually amortizing differences between costs and rates), or they can be passed downstream fully and rapidly to customers (in a rate adjustment clause, thereby increasing customer risk but avoiding a risk premium in the average price of supply for that problem). There is no “right” or *per se* dominant answer for where the best place is to assign and compensate risk. This is a matter of risk tolerances and of

[15] Correlation is a statistical measure of the extent to which uncertain factors tend to change in the same direction.

the ancillary consequences to the parties from being exposed to risk. This means that portfolio management objectives and the resulting preferred portfolio cannot be chosen solely on its face, but must be sorted out among a utility, its regulators, and its customers. A supply strategy should be selected that conforms as closely as possible to their risk tolerances, financial capabilities, and administrative abilities to implement and monitor the design.

The goal of SOS portfolio procurement and management should be to achieve a specified range of acceptable risk, not to try to "find bargains" or "beat the market." In efficient markets, there is a specific trade-off between price and risk, such that the risk-adjusted cost (*i.e.*, the expected present value) of two different portfolios should be virtually identical, particularly when transaction costs are sufficiently low. Electric power markets, such as the trading of energy at the PJM hubs, are deep markets where many sophisticated players participate. One would not expect such markets to be susceptible to sustained periods of mis-pricing across products of different durations and risks. If there was any such mis-pricing, traders would step in to buy the relatively low-priced product (*e.g.*, an under-priced forward contract) and re-sell that product into the market in another form (*e.g.*, as spot power). Under this kind of competitive pressure, prices should reflect the underlying market conditions affecting the products.

Because the primary goal of portfolio management is procurement of supply at an acceptable price and risk, it is not possible to state categorically what supply elements a desirable portfolio should include. That question can only be answered with a clear understanding of the underlying needs and constraints facing the customers and SOS provider. However, experience in other SOS resource planning settings suggests that a typical goal is to achieve reasonable rate stability while staying roughly in line with wholesale market prices over a two- to three-year horizon. It is appears to be generally the case that customers and regulators want to manage both "risk" and "regret". Risk is the *ex ante* exposure to future uncertainty. It is reduced through hedging and transfer of risks to suppliers, so that future service prices and terms are more certain and knowable in advance. Regret is the *ex post* exposure to disappointment from having a higher resulting SOS price compared to some alternative strategy (known only in hindsight to be attractive) that might otherwise have been pursued. It is impossible to simultaneously minimize both risk and regret.[16] The best one can do is to balance them against each other, so as to not be unduly vulnerable to either future risk or to the hindsight possibility of unfortunate market timing. With that tradeoff in mind, a desirable portfolio could include some of these elements: (i)

[16] Minimizing regret may also help to reduce certain risks and administrative complexities of a strategy that would otherwise focus on *ex ante* risk. In particular, credit risks may be greater for a strategy that seeks to lock down future prices long in advance, due to the risks of supplier failure and/or the consequences of mark to market accounting and collateralization of positions that become "out of market." The imputed cost of debt from long term forward commitments at fixed prices for a utility may also raise the cost of a strategy focused solely on *ex ante* risk.

long-term forward purchases of perhaps 1-5 years in length; (ii) shorter term installment purchases with seasonal prices staggered over time; and, (iii) some reliance on the spot market.

- Long-term forward purchases at a fixed price and volume can be used to cover "baseload" needs and reduce the seasonal variability of portfolio costs. Such purchases transfer price risk to the seller, but they are exposed to potential credit problems and *ex post* regret. Since these contracts are sizable and long-term, the market position of the counter-party supplier can grow rapidly "out of market" if wholesale electricity prices subsequently rise, making bankruptcy risk and the replacement-energy price risk a legitimate concern. This "counter-party risk" may be reduced but not eliminated by using multiple suppliers.[17]

- Staggered purchases, *i.e.*, buying a portion of next year's needs in installments over the preceding months, is sometimes referred to as "dollar cost averaging" (DCA). It is analogous to the personal investment strategy of buying stocks steadily over time, rather than trying to time the market. For instance, purchases could be made in twelve equal monthly installments beginning approximately one year ahead of delivery schedule. Such purchases must occur in 50 MW blocks, the standard contract size in PJM. Accordingly, some purchases may have to be delayed until standard block size is feasible. Procuring power via staggered purchases helps to mitigate "regret risk," because by spreading out multiple forward purchases over time and across several parties, the impact of any single inopportune purchase is lessened and counter-party risk is diversified. Of course, the opportunity to have inadvertently bought all of one's needs at a fortuitously low price is also foregone, and the uncertainty in future prices is kept open for longer, but that is always the tradeoff if one wants to avoid regret.

- Spot purchases for a modest portion of total needs (especially in peak hours) are desirable, because this is a flexible way of coping with unanticipated variations in load due to weather and/or customer switching to and from competitive retail suppliers. Covering this volumetric uncertainty with spot supplies *whose average cost flows through to customer*s avoids the portfolio risk premium that would otherwise accompany bearing that risk over time at a fixed price. This lowers the expected, long-run average costs of the portfolio somewhat – though at the expense of having customers share

[17] To some extent, all of the multiple suppliers will face similar market problems at the same time, much like one cannot diversify oil price volatility by relying on multiple producers.

some of the risk. If the percentage of spot purchases in the portfolio is not too high, that risk is not too large, and doing so has other advantages: [18]

- Spot market purchases have no exposure to counter-party risk.

- Serving the top portion of total needs with spot purchases supports the creation of efficient price signals that facilitate the integration of Demand Response (DR) and smart meters (AMI). DR and AMI are major components of PHI's Blueprint for the Future.

- Having an SOS price that rises and falls gently along with wholesale market prices reduces customer switching risks, thereby reducing the complexity and cost of covering SOS.

By varying the proportions of the above, and the timing of their procurement relative to the delivery dates for SOS service, the risk characteristics of the portfolio can be managed to within acceptable bounds. The inclusion of physical resources in addition to, or in lieu of, some of these contract elements further alters the average cost and the range/pattern of risk. A Monte Carlo simulation model can be used to predict the likely ranges of future electricity costs to RSCI SOS customers under different combinations of portfolio resources.[19] The Brattle Group has developed such a model that has been applied here to project annual average costs per MWh in 2010-12, 2015, and 2018.

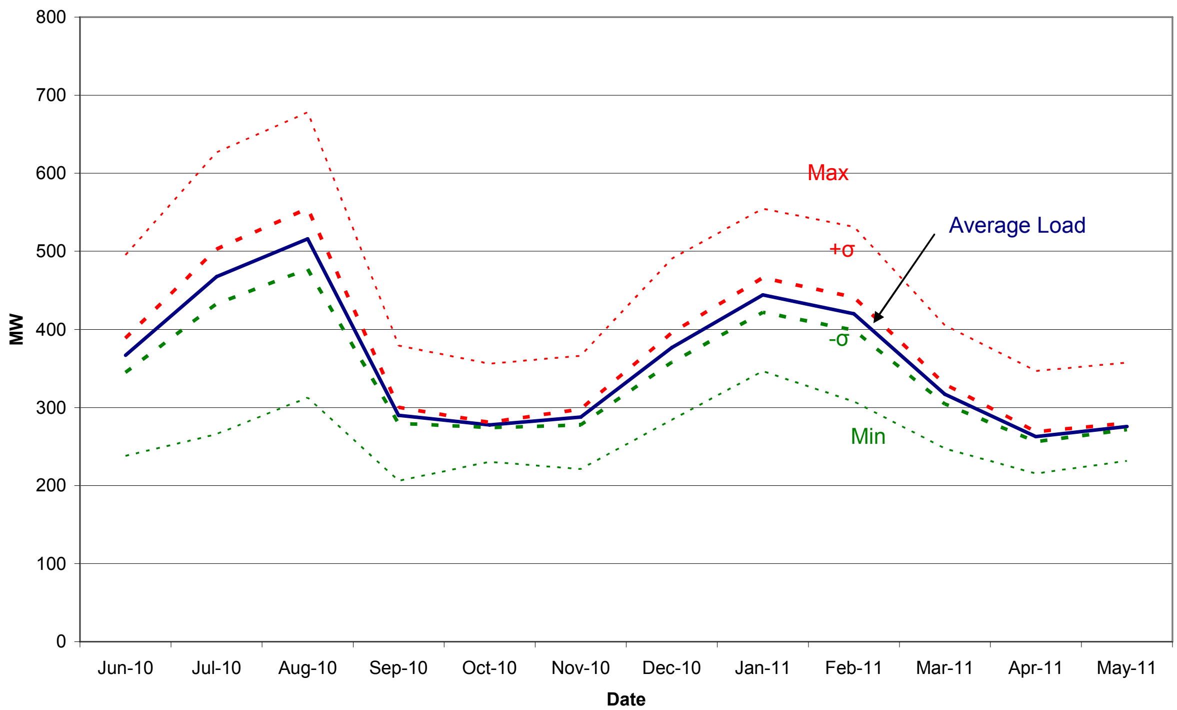
The average projected hourly load levels (by month, in MWs) for Delmarva's RSCI customers for the twelve months beginning June 2010, along with the associated typical weather uncertainty

[18] In addition, the price variability during off-peak hours is not nearly as large as on-peak. (Most off-peak hours are served by baseload units in PJM, which tend to have more stable fuel costs and similar heat rates, compared to peaking units.) Accordingly, it can also be reasonable and administratively efficient to procure off-peak needs not served by baseload contracts with spot purchases.

[19] The term "Monte Carlo" modeling was coined by scientists at the Los Alamos laboratory during World War II. It involves the use of simulated random sampling of possible conditions to project how an economic or engineering system can be expected to perform.

considered, are shown in Figure 2 below.

Figure 2: Average, Min and Max DPL DE Peak Hourly Load for RSCI Customers



This figure reflects only the load during on-peak hours for residential and small commercial customers projected from historical load experienced over June 2006 through April 2008, and adjusted for potential conservation impacts of Delaware's Sustainable Energy Utility (SEU) programs.[20] Note that the average load is around 360 MW, while the minimum hourly load is around 210 MW (again, for peak hours). The minimum hourly load for off-peak periods is about 170 MW. This means that annual or staggered forward contracts up to around 150 MW could be used to serve the baseload portion of total needs. The weather uncertainty surrounding average monthly loads is not very large, a few percent.[21] Maximum hourly loads can be over 1.3 times the average for any given month, with an annual peak of almost 700 MW. However, high load levels occur in relatively few of the hours in a month, making it more appropriate to cover them with spot purchases. This is more easily seen when viewing the hourly load levels for both on and off peak periods reordered from highest to lowest, as an annual "load duration curve" shown below.

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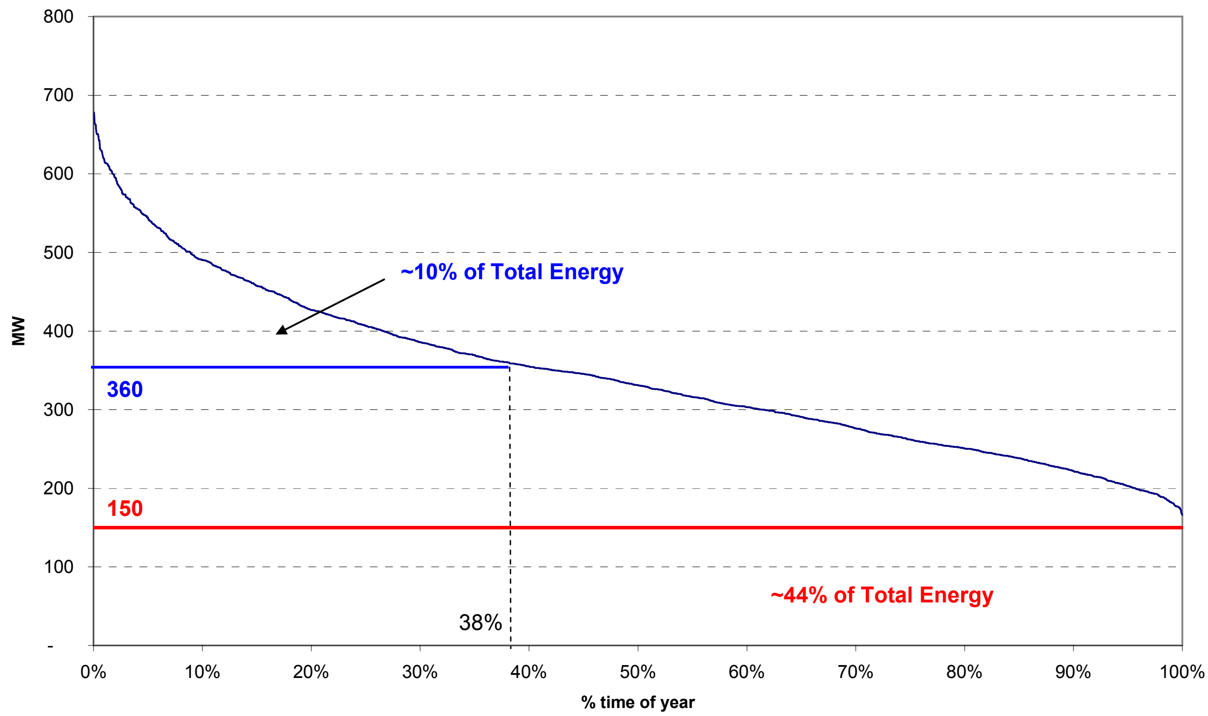
[20] The conservation projected herein is based on cost-effectiveness assessments by ICF International under the same market conditions affecting the RP in this report, not on specific activities announced or underway by the SEU.

[21] The weather uncertainty simulated here is not specific to PHI, but is realistic for utilities in PJM. Daily and hourly weather uncertainty, not reflected in this analysis, would be much larger.

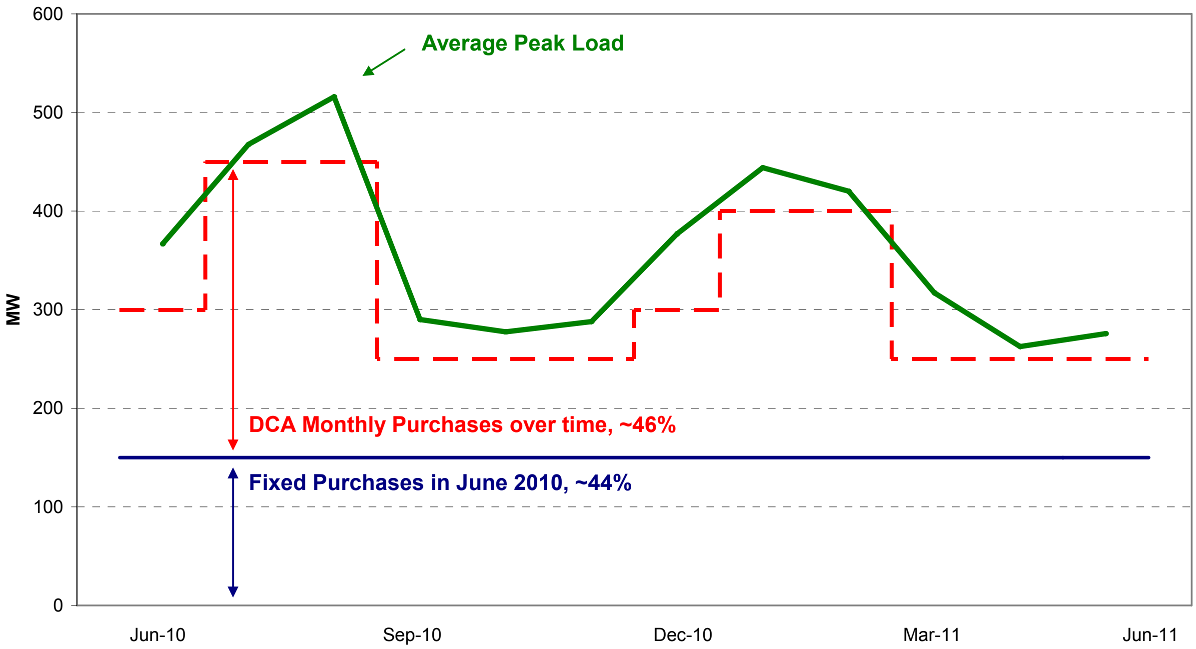
Figure 3: RCSI SOS Load Duration Curve for 2010 (DPL)



Note: Based on historical intraday pattern created for a representative week every month.

The lower, red horizontal line in the above graph indicates that 44% of annual RSCI SOS energy requirements arise due to a minimum level of demand of around 150 MW. A fixed-price, multi-year, 7 * 24 baseload contract could be devoted to this, and it would face very little quantity risk of not being fully needed. The upper, blue horizontal line, at around 360 MW, is drawn where demands above this level comprise 10 percent of total annual needs. This peak portion of total needs could be satisfied with spot purchases, without having the resulting volatility of average costs be too large. The middle region, from 150 to 360 MW, could be satisfied with staggered, DCA purchases of seasonally priced monthly forwards. The monthly result of this portfolio composition is shown below in Figure 4. Similar to the foregoing graphs, this figure uses projected loads for the twelve months beginning June 2010. (This is also the beginning delivery period for all simulated portfolios.)

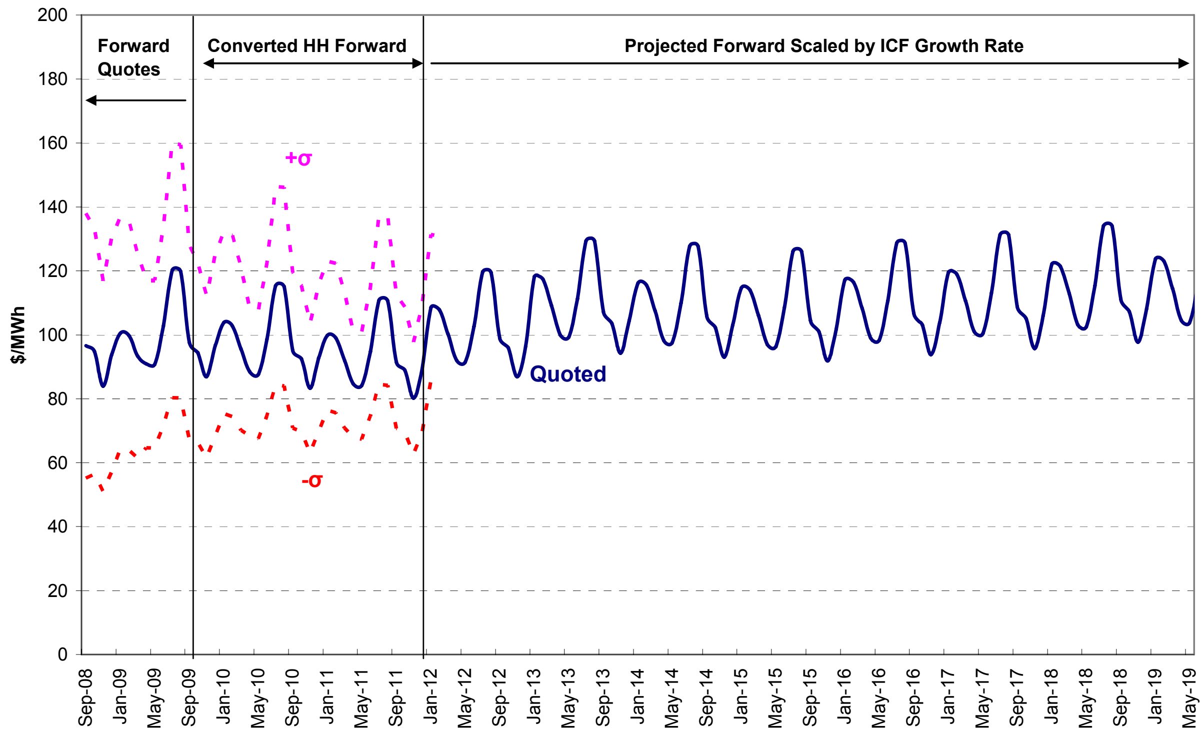
Figure 4: Portfolio layers shaped to match on-peak seasonal load (June 2010 to May 2011)



The above provides the basis for the managed portion of an SOS portfolio. (The other components of the portfolio include the FR contract and wind resources.)

The other key input to portfolio planning and risk analysis is of course the expected prices and uncertainty associated with future power purchases. Market outlooks for both of these can be obtained from broker quotes for forward on-peak monthly sales. As of August 1, 2008, the estimated on-peak forward curve at PJM-West, plus average monthly congestion into the Delmarva zone, appeared as follows through 2018:

Figure 5: Estimated DPL Forward Peak Price with Uncertainty as of 08/01/2008



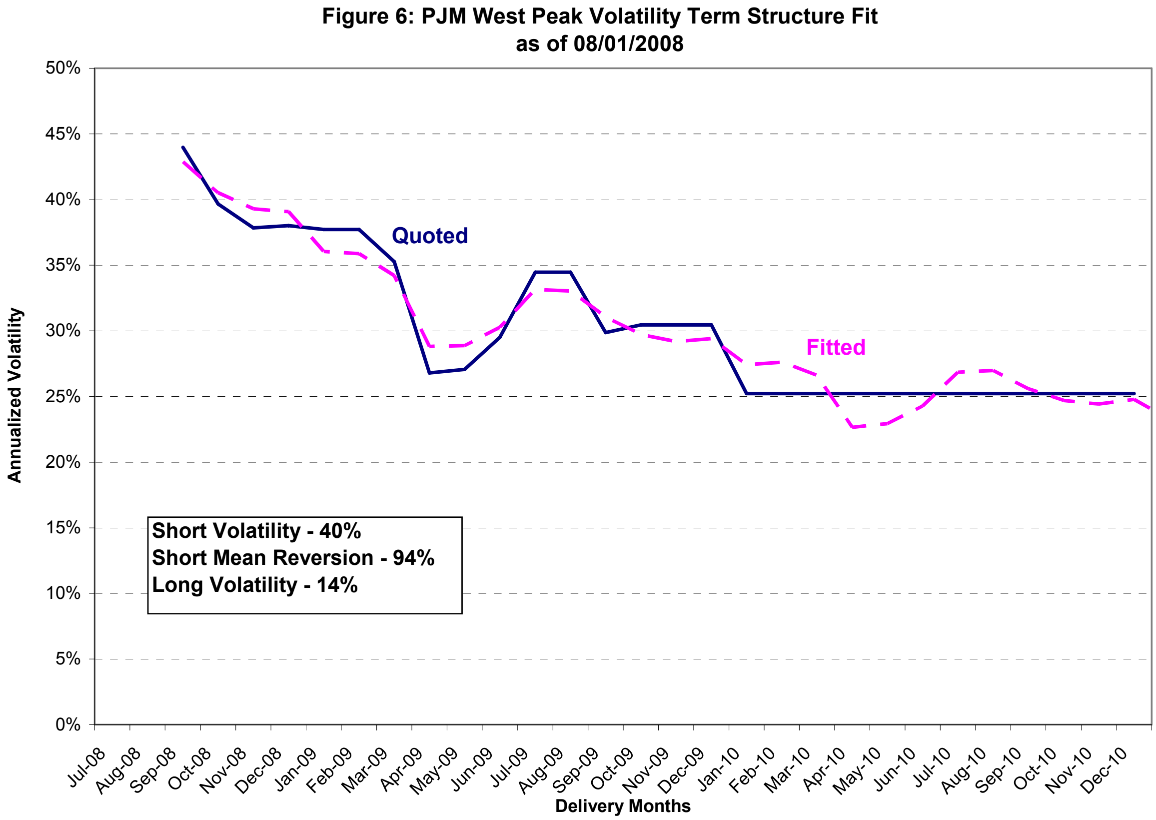
In this graph, the dark blue line is the on-peak monthly price of power as it was being offered on August 1, 2008, and adjusted for congestion to Delmarva. Note that prices fall slightly for the first two years, corresponding to a reduction in natural gas forward prices (not shown), and then they rise by about $10/MWh by 2013, largely due to the assumed introduction of CO2 prices beginning in that year.

There are two vertical lines in the above figure, one at November 2009 and the other at January 2012. The first line represents the end of the time frame over which electricity futures with monthly prices were quoted at PJM-West (as of August 2008). Typically, electricity futures are only quoted on a monthly basis for about 12-18 months forward. To obtain market-based forward prices thereafter, we extrapolated the PJM electricity forwards by the Henry Hub natural gas forward prices, which are traded up through the end of 2013. To convert gas to electricity, we scaled each monthly Henry Hub price by the historical average heat rate implicit in the ratio between PJM electricity prices and Henry Hub gas prices. This approach is used until 2012, the second vertical line, beyond which we extrapolate the prevailing monthly pattern at the growth rate(s) obtained by ICF in its fundamental modeling of PJM prices.

The congestion component in the above was also modeled in different ways. For the first period when market forwards are available, the historical monthly average day-ahead LMP differences between PJM-West and the Delmarva zone are added. In the third period, the growth rates for ICF's projected LMP differences for those same locations are used. In the middle period, the historical congestion is interpolated to ICF's projected congestion.

The dashed pink and red lines above and below the blue line in Figure 5 depict the ranges around those forward prices that describe the uncertainty power market brokers perceive for what actual average monthly spot prices could turn out to be. Like the monthly forward price, the monthly uncertainty has a pattern of seasonality, being greater for certain months, as well as having a tendency to dampen over time. Those probability ranges were obtained from brokers, who in turn infer them from the price of call option contracts trading for those future delivery months. The price of an option depends on the volatility of the underlying commodity or security upon which the option is based. That is a key element of the well-known result obtained by Black and Scholes regarding the appropriate option price. Accordingly, the price of traded options can be "reverse engineered" to calculate the "implied" volatility in a future delivery period that is implicit in the corresponding option price.

The expected volatility of energy prices differs depending on what delivery month is being considered, as well as on when it is being considered, *i.e.,* on how far one is looking into the future. This must be taken into account when simulating how prices for DCA purchases occurring in installments in future months may change relative to today's prevailing forward prices. To do this, a statistical model is fitted to the volatility quotes to obtain a price volatility function that can be used for any given purchase date and delivery period in the future. The results are shown below in Figure 6. This function is used to simulate how forward prices for power could change between now and future procurements, and what degree of uncertainty to expect in average monthly spot prices for power in the delivery month (for the portion of load covered by spot).



With the above, along with the corresponding information on natural gas prices and wind plant performance, the analytic components necessary to simulate managed portfolios are available. Using these prices and the associated price-volatility function, the simulation model randomly "draws" a set of future forward and spot prices that will be pertinent for purchase dates in the future. Based on weather-related load uncertainty, the loads for each month are also "drawn" by the simulation model, so that the required quantity of spot purchases can be calculated. Only the level of monthly spot prices is uncertain in the model. Intraday price patterns are recognized deterministically, with hourly price and load shapes specific to each month; hourly uncertainty in these two factors is not modeled. For each price-load draw, a calculation is made of the resulting portfolio costs. The simulation model repeats the draws over and over (1000 times in this case) to obtain a set of projected outcomes that span the likely range of possible costs in each future delivery period. The average of all the draws is the current forward price of power. The riskiness of the alternative portfolios can then be visualized and compared using graphs that depict the range of potential delivered costs along with their associated probabilities.

The Reference Portfolio (RP) consists of a managed portfolio (MP) of wholesale contracts, plus the wind resources and the existing FR contracts. The MP portion is comprised of 150 MW baseload (all hours), three-year, fixed-price contract for 2010-2012 (as if purchased in February, 2010), DCA monthly purchases beginning June, 2009, twelve months before delivery date, and spot purchases. Delaware's Renewable Portfolio Standards are satisfied by the Renewable Energy Credits (RECs) created by the wind resources.

RESULTS – INITIAL PERIOD, 2010-2012

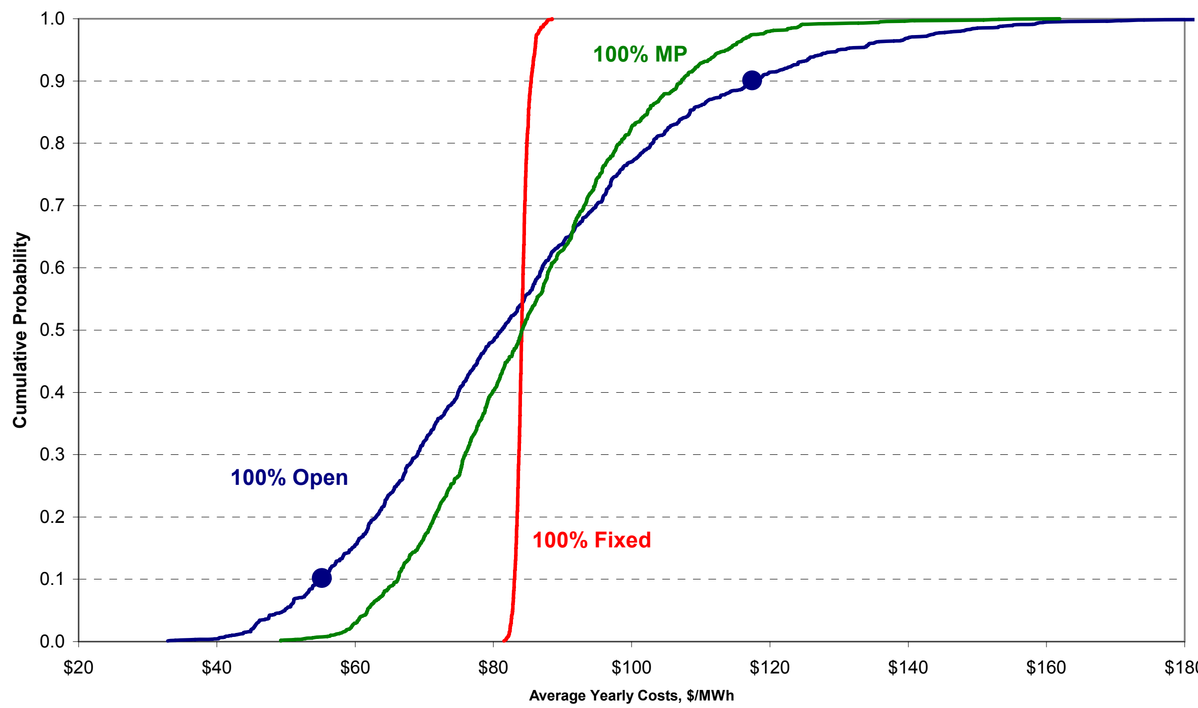
The MP purchasing matrix for on-peak requirements in 2010, describing when forward commitments are struck for each delivery month, is shown in Figure 7. (Off-peak purchasing consists exclusively of the 150 MW annual block and spot purchases, so it does not require a matrix of planned procurement times.) The rows in this matrix indicate when purchases will be made for the dates shown in the columns. The cell amounts are the quantities to be purchases under either a multi-year, fixed price contract (top row) or in steady DCA installments, albeit deferred until 50MW blocks are feasible. The residual requirements are satisfied with spot purchases.

Figure 7: On Peak Procurement Schedule

Monthly Blocks	17,600	16,800	17,600	16,800	16,800	16,800	18,400	16,800	16,000	18,400	16,800	16,800
Purchase Dates	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**May-11**
Fixed Upfront Purchases	52,800	50,400	52,800	50,400	50,400	50,400	55,200	50,400	48,000	55,200	50,400	50,400
6/1/09	-	-	17,600	-	-	-	-	-	-	-	-	-
7/1/09	17,600	16,800	-	150 MW Block		-	18,400	16,800	16,000	-	-	-
8/1/09	-	-	17,600	16,800	16,800	16,800	-	-	-	18,400	-	16,800
9/1/09	-	16,800	-	-	-	-	-	16,800	16,000	-	16,800	-
10/1/09	-	-	17,600	-	-	-	-	-	-	-	-	-
11/1/09	17,600	16,800	-	-	-	-	18,400	16,800	16,000	-	-	-
12/1/09	-	-	17,600	-	-	-	-	-	-	-	-	-
1/1/10	-	16,800	-	16,800	-	16,800	-	-	-	18,400	-	-
2/1/10	17,600	-	17,600	-	16,800	-	18,400	16,800	16,000	-	-	16,800
3/1/10	-	16,800	-	-	-	-	-	-	-	-	16,800	-
4/1/10	-	-	17,600	-	-	-	-	16,800	16,000	-	-	-
5/1/10	-	16,800	-	-	-	-	-	-	-	-	-	-
Total DCA and Upfront Purchases	105,600	151,200	158,400	84,000	84,000	84,000	110,400	134,400	128,000	92,000	84,000	84,000
Spot Purchases	20,570	9,641	19,115	15,795	11,473	14,988	19,178	18,379	16,496	17,081	6,349	10,840
Total Peak RCSI Volume	126,170	160,841	177,515	99,795	95,473	98,988	129,578	152,779	144,496	109,081	90,349	94,840

Figure 8 below shows how <u>just the energy costs</u> of an SOS portfolio depend on its composition and when it is purchased. Purchasing more and sooner reduces the portfolio's risk. This can be seen below by comparing the slopes of curves corresponding to different purchasing strategies. The slope of these S-shaped curves reflects their risk, with a vertically steeper curve being less risky (less chance of a wide range of realized annual costs) and a wide, flat curve being more risky. If all of 2010's average monthly needs were to have been purchased on August 1, 2008, at the prevailing forward prices, then there would be very little risk surrounding the future price (of energy) in 2010. Just a bit of risk remains, from the uncertain residual costs of balancing average forward purchases in flat blocks against the more complicated, weather-sensitive daily load shapes. The resulting S-curve (shown in red) is almost completely vertical. Of course such a purchase was not made, and the first reasonable time to consider doing so would be around the middle of next year.

Figure 8: Comparative Risks of Different Procurement Strategies - Energy Only Expected Costs in August 2008 for June 2010-May 2011 Energy Requirements

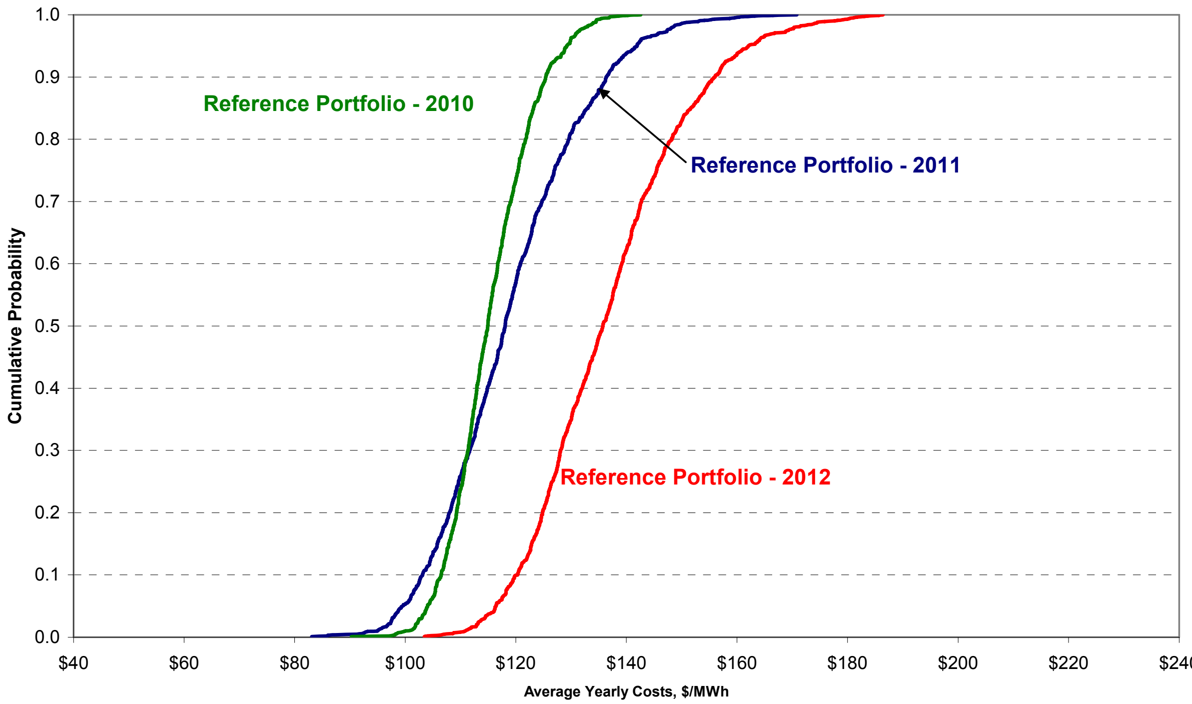


A much riskier strategy would be to defer all power purchases until the demand arises, i.e., to buy all power at spot. The range of potential average annual costs per MWh from this strategy is shown above as the dark blue, wide S-curve labeled "100% Open." This curve spans a large range of possible average annual prices (along the x-axis). Its 10^{th}-percentile level, indicated with a circle at that point on the curve, is $55.14/MWh; there is only a 10% chance that the average annual cost will be <u>below</u> this level. Its 90^{th}-percentile level (also indicated with a circle) is $117.28/MWh; there is only a 10% chance that average annual spot prices for the RSCI load will be <u>above</u> this level. If that should occur, the average price per MWh in the top 10% of all scenarios is $135.26/MWh. Financial portfolio managers often use measures like this over different horizons, relative to different thresholds and different risk factors, to manage their investments exposure to extreme conditions.

The difference between the all-spot and the all-at-once curve is the distribution of possible regret (or satisfaction) from having bought in advance. That is, as the risks appeared on August 1, 2008, there was a good chance that spot prices could come out much lower (regret) or much higher (satisfaction) than the then-prevailing forward curves. Procuring some power in DCA installments strikes a balance between these, and it may reduce other costs of risk management as well (such as credit, and volume errors). This effect is seen in the green, S-shaped curve above for the MP, which buys about 46% of peak needs on DCA, and so it lies between the curves for all-at-once purchasing and all-spot purchasing. This portion of the portfolio will change in response to changing market conditions, but to a much lesser extent than spot procurement would.

Figure 9 adds the non-energy costs to the MP for capacity and ancillary services, along with the effects of the FR and wind contracts, to get the full costs of the Reference Portfolio. It also depicts the range of RP prices for 2011 and 2012. The capacity and ancillary services costs add about $23/MWh to the total cost in 2010. The curve shifts a bit to the right (becomes more costly) in 2011, and it becomes more risky (less vertical). The shift occurs primarily because PJM capacity prices in the Delmarva zone increase in 2011 (and more in 2012). The curve becomes less vertical (riskier) than in 2010 because the existing FR contract expires on May 31, 2011, so the only portion of the 2011 RP supply that has fixed prices already in place as of August 2008 is the wind contracts. Also, the MP purchases for 2011 are a year farther in the future than the MP purchases for 2010. The curse shifts even further to the right in 2012 due to a continuing increase in capacity prices.

Figure 9: Comparative Risks of Different Procurement Strategies
Expected Costs in August 2008

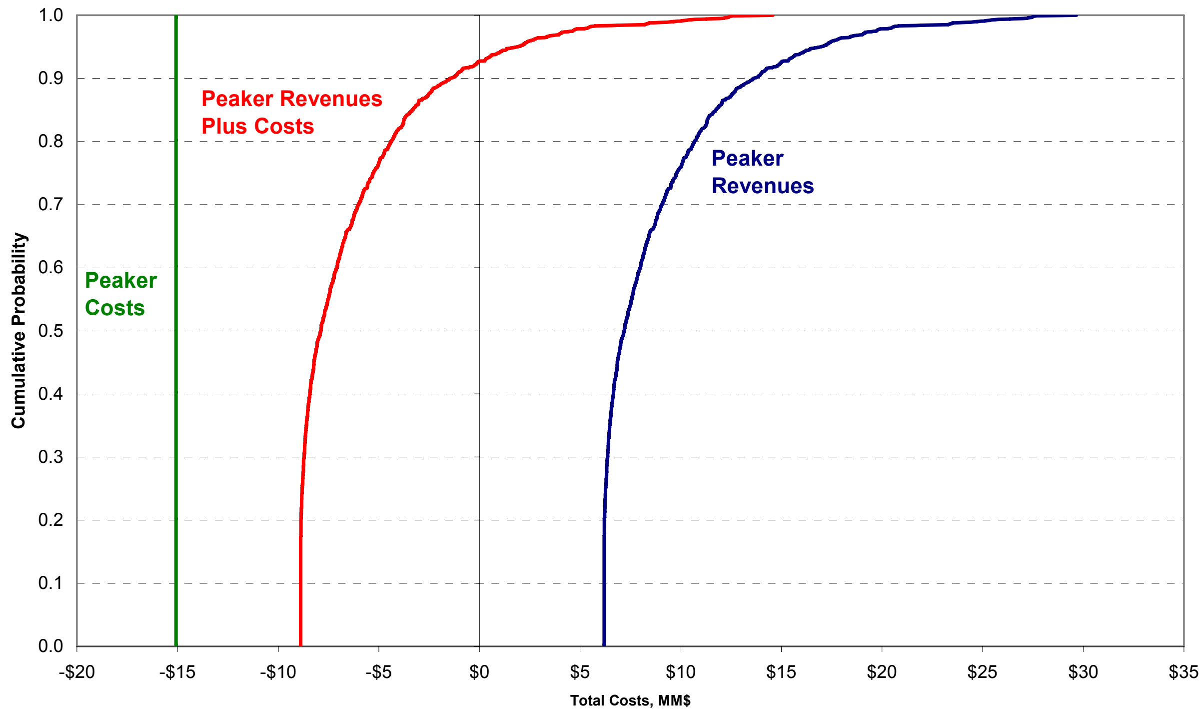


Long-Term Gas-fired Generation Assets

Because of rising congestion and capacity prices in PJM (as well as uncertainty over the completion of announced transmission projects), it is worthwhile to evaluate whether a gas-fired generation plant could reduce the costs or risks of RSCI SOS service. This prospect has been evaluated by considering the following two scenarios: 1) buying a 100 MW CT in 2010 and treating it as a regulated asset with cost-based pricing; or, 2) entering into a 10-year contract for 100 MW of the output of a CC, simulated at the levelized nominal carrying charges for a new CC with the fuel costs incurred at the monthly spot prices of natural gas delivered to eastern PJM.

The initial year, stand-alone economics of the CT are shown in Figure 10. It compares the annual fixed costs of the peaker to the revenues foreseeable in the Delmarva zone from its spot energy sales and capacity (under the same simulated market conditions as experienced by the MP). The net revenue curve is in the middle, and it is rarely positive. On average, it would not recover its expected annual costs in 2010. Instead, it would incur a first-year loss of about $6.3 million, and in so doing it would raise the average price of the MP by about $2/MWh. Since the energy production from a CT is fairly small (especially under the simulated 2010 conditions), it has only a slight effect on energy risk. (Owning a CT would provide a hedge against uncertain capacity prices. However, capacity price risk has not been modeled in this study.)

Figure 10: CT Revenues and Costs
Expected Costs in August 2008 for June 2010-May 2011 Requirements



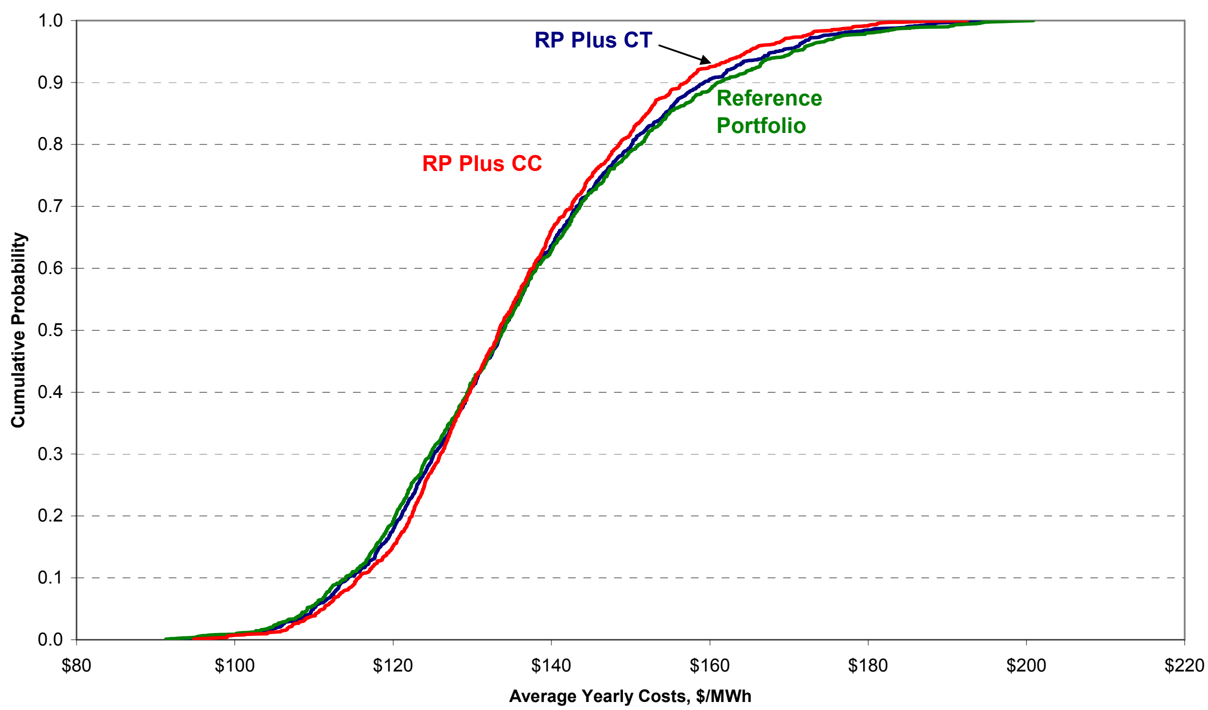
The CC contract has been simulated as if it were under a fixed-price, level nominal PPA for the non-fuel charges (at a merchant cost of capital) with a cost-based variable charge for its fuel (akin to a tolling agreement). Simulating its production in the Monte Carlo model, with randomized gas and spot power prices based on gas forward curves and volatilities, the CC achieves about a 30% capacity factor in 2010. This is close to recent experience for CCs in PJM. It is a bit more attractive than the CT, but it too would be just slightly below breakeven in 2010 with a cost recovery deficit of $3.84 million, causing a $1.29/MWh increase in the RP's average cost. If the CC were priced as an owned asset, under cost of service regulation, its capital recovery charges would be slightly higher in the early years, making it even less attractive (although eventually more attractive, thanks to the declining capital charges). However, a CC does reduce the risk of the RP a bit, because it produces profitable energy in peak hours, thereby offsetting some of the risky spot power costs in the MP.

RESULTS – 2015

Results for 2015 are simulated as though the FR RFP process is renewed and pursued every three years for 1/3 of the net RSCI SOS load. These future procurements are assumed to occur in June 2012 for 2013-15 and June 2015 for 2016-18. In fact, they may occur on other schedules and/or in more frequent, smaller installments. However, their costs and risks (price uncertainty as seen from today) are likely to be quite similar to the costs and risks of the MP – since that portfolio is also designed to cover the full requirements of the same RSCI SOS customers, and it will be comprised of the same types of contracts that will be available to bidders in the future RFPs. Accordingly, simulating the FR procurements as less frequent, larger events does not alter the basic character of the expected RP results.

2015 is investigated here in order to determine if gas-fired generation becomes more or less attractive by then. Figure 11 depicts the cost per MWh distributions for the RP in 2015 with and without the regulated CT or the CC PPA. Note that these S-curves are roughly twice as wide as the similar curves for 2010-12, for two reasons. First, there is no fixed price FR contract in place for 2015, unlike 2010. In addition, these curves now depict the degree of uncertainty surrounding those 2015 prices as of 2008, with seven years to go before delivery of that power. By 2013, pending purchases for 2015 will not look any more risky than those for 2010 do today (to the extent that basic market conditions do not change materially).

Figure 11: Comparative Risks of Different Procurement Strategies
Expected Costs in August 2008 for June 2015-May 2016 Requirements



As can be seen from the fact that these curves are so tightly overlapping, there is very little average net benefit or cost from the gas resources in 2015. In fact, both would decrease the average cost of the RP in 2015, but only trivially -- by less than $1/MWh. They would also reduce risk a bit, as seen by the slightly more vertical curves above when they are included.

RESULTS – 2018

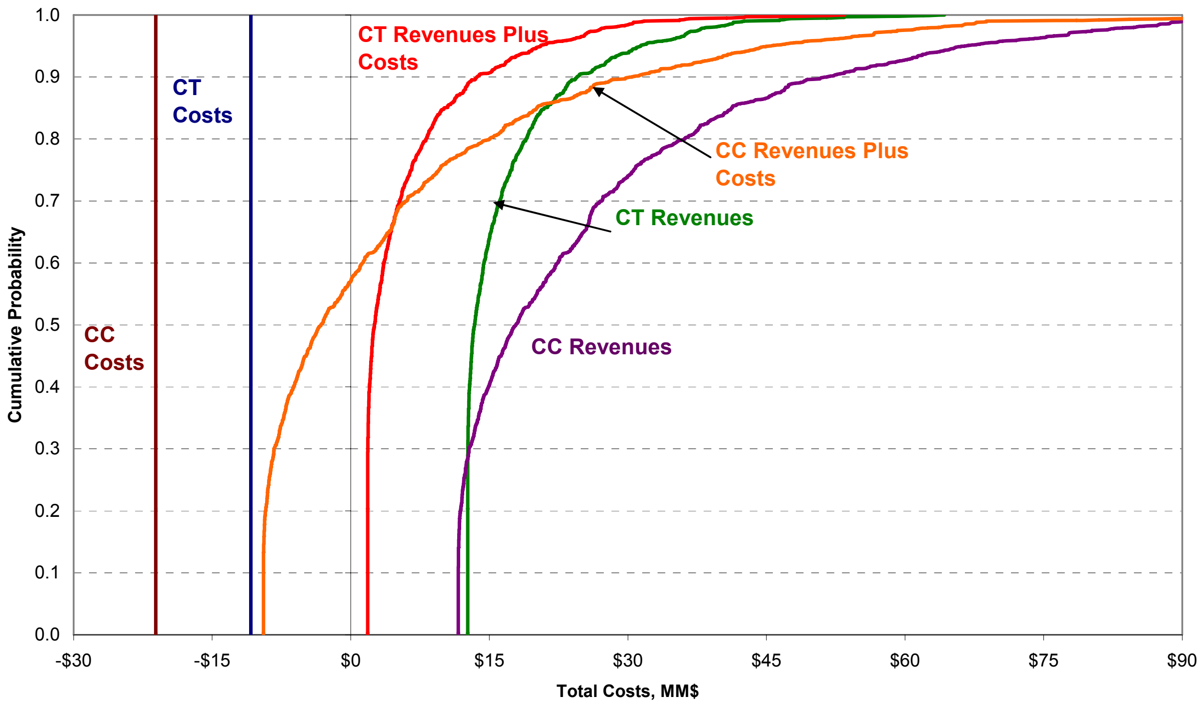
This study reflects the assumption that U.S. CO2 pricing will begin in 2013, and by 2018 it could become a material factor in energy prices. A $10/ton CO2 price can be expected to raise the average wholesale price of power in PJM by about $5 to $6/MWh. This occurs because the dispatch price of coal-fired generation (at a 10,000 Btu/kWh heat rate) increases by about $10/MWh per $10/ton CO2, while the cost of generation from natural gas rises by about $4/MWh for a CC and $6/MWh for a CT. Since coal and gas are often on the margin in PJM dispatch, their increased costs will raise the market price.

The wind resources Delmarva already has under contract should provide a hedge against CO2 (and high fossil fuel prices, should that occur). Gas resources are a source of CO2, but less so than coal-fired plants, and they may well be the most economical expansion alternative for a while, unless and until CO2 prices become quite high. Figure 12 shows the annual cost and net revenue curves for the CT and CC gas generation. By 2018, a regulated CT purchased in 2010 appears likely to be reliably attractive. It has net benefits in 100% of the simulated Monte Carlo scenarios. This occurs because its annual carrying costs have decreased due to its nominal capital recovery against a rate base value that is depreciating.[22]

The CC PPA also gains value by 2018, though less reliably so. In more than half of the projected scenarios, it would have a net negative value, but it has potential for quite high value in some scenarios. On balance, it would have an expected positive value, such that its addition to the RP would lower RP average costs by about $1.50/MWh. The CT would lower them by about $2/MWh. The CC also reduces RP risks, from a 10th -90th percentile range of almost $64/MWh to about $55/MWh.

[22] If it should turn out that conservation or demand response programs are less successful than is hoped, a CT would also provide important reliability (and, relatedly, capacity price) mitigation benefits in 2012 and beyond. Again, such benefits are not quantified in this report.

Figure 12: CT and CC Revenues and Costs
Expected Costs in August 2008 for June 2018-May 2019 Requirements



CONSIDERATION OF RECENT MARKET MOVEMENTS

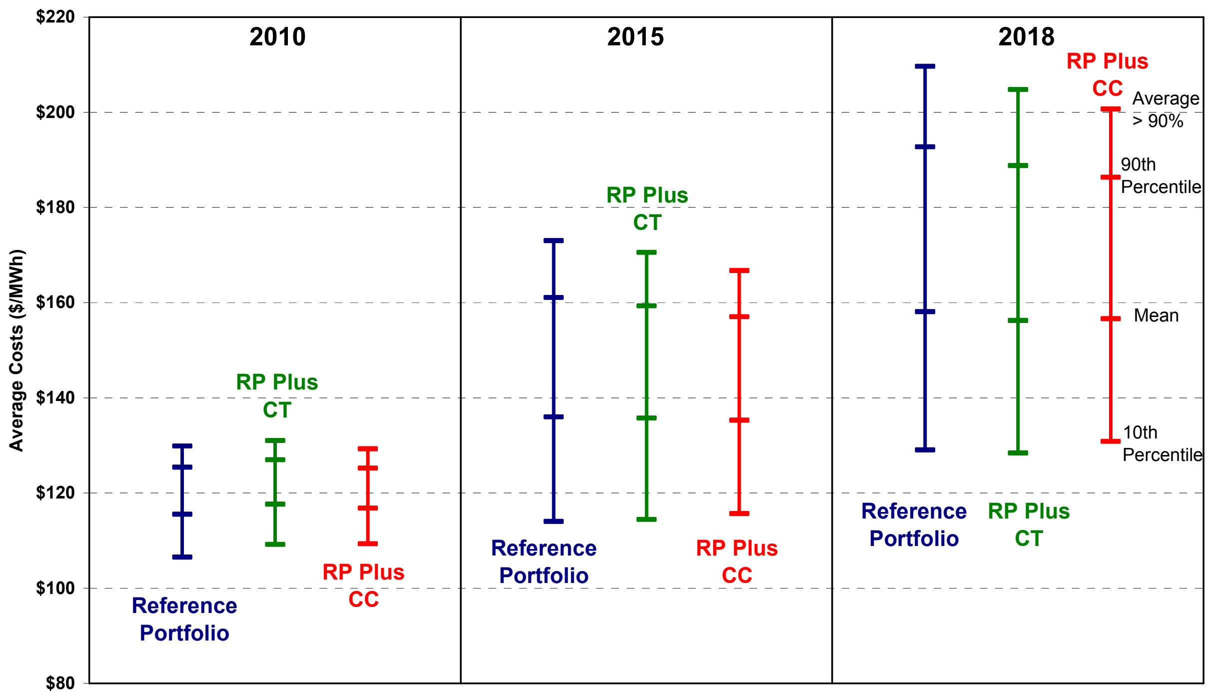
Since the data was developed for this analysis in late summer, the spot and forward prices of gas and power have both declined markedly, apparently in reaction to the recessionary pressures created and revealed by the credit crisis. For example, prices for the calendar strip 2009 are down by about 25-30% for electricity and about 20-25% for gas.

Everything else equal, this may make a gas-fired plant less attractive in the short run than the above analysis above would suggest. It is more difficult to say what this means for the long run attractiveness of gas-fired generation. This will depend in part on how deep the financial crisis is, and on whether it deters supply expansion as much or more than it reduces demand growth. (This will affect capacity prices, which are a significant portion of the cost recovery for gas units.) It is also very difficult to tell whether current energy prices reflect a true view of the future, or a panicked one that may be disconnected from sustainable fundamentals. Accordingly, this analysis has been based on pre-crisis market parameters, but they should be considered quite uncertain.

SUMMARY AND CONCLUSIONS

Figure 13 puts all of the 2018 results together. It depicts the RP performance with and without a CT or CC in 2010, 2015 and 2018. However, instead of being shown as S-curves, the results are shown as a vertical line with a few short horizontal lines along it. The lowest of these indicates the 10^{th} percentile cost per MWh (bottom of each vertical line). The next (towards the middle of each vertical line) indicates the expected value for the RP cost in that year. The 90^{th} percentile is indicated by the dash near the top of each line, and at the very top of each line is a dash for the RP's average cost above 90% (expected cost of the highest 10% of outcomes).

Figure 13: Comparative Risks of Different Procurement Strategies
Expected Costs in August 2008



This figure shows several things: First, the center of the lines rises by about $40/MWh by 2018. These values are stated in nominal terms, so that is about $31 in constant 2008 dollars (at 2.5% inflation).

Second, the lengths of the lines increase from 2010 to 2018. This means that the RP becomes riskier, with wider ranges of possible future average annual costs. This occurs initially because the existing fixed price FR contract expires, and thereafter because of the increasing amount of time between now and those future years. It is not because 2018 is likely to be riskier in 2018 than 2010 will be in 2010. Rather, 2018 is much more uncertain than 2010 from the perspective of 2008.

Third, adding 100 MW of gas to the portfolio would slightly raise its costs in 2010, by about $2/MWh, and would slightly lower them by about the same amount in 2018. A CT has a lower average expected cost, but there is really not enough difference in their expected costs to determine from this analysis if a CC or CT would be more useful. A CC would lower the riskiness of the portfolio, particularly by 2018. However, these results describe generic CTs and CCs. Expected costs and locational benefits at actual potential sites in DE would have to be evaluated to determine if there would be meaningful benefits to a specific resource.

Finally, recent events make it more difficult to be confident of the expected value of forecasts in general. Load growth, commodity prices, capacity expansion, risk premiums, and the costs of financing (or collateralizing long term contracts) may well be affected. The net impact will not necessarily be to make future power cheaper than the projections herein, even though recent energy forward prices have declined. Risk management goals and policies may now be as or more important to Delmarva's customers as trying to identify the "lowest cost" mix of resources.

IV. Reliability and Generation

1. Long Term Transmission Planning:

Delmarva Power's transmission facilities are located within the PJM Regional Transmission Organization ("RTO"). Delmarva Power works with PJM to ensure that reliability standards are met and that the necessary transmission facilities are built to meet the short term and long term needs of the Delmarva Peninsula.

PJM, as the RTO, is responsible for ensuring:

- Adequate generation or demand side resources across the entire region,; and
- Adequate transmission capacity to reliably and efficiently deliver the generation capacity where it is needed.

PJM meets these objectives by administering competitive markets that encourage merchant generation, transmission and demand-side resources. In addition, PJM as the regional planner identifies necessary transmission enhancements, in conjunction with

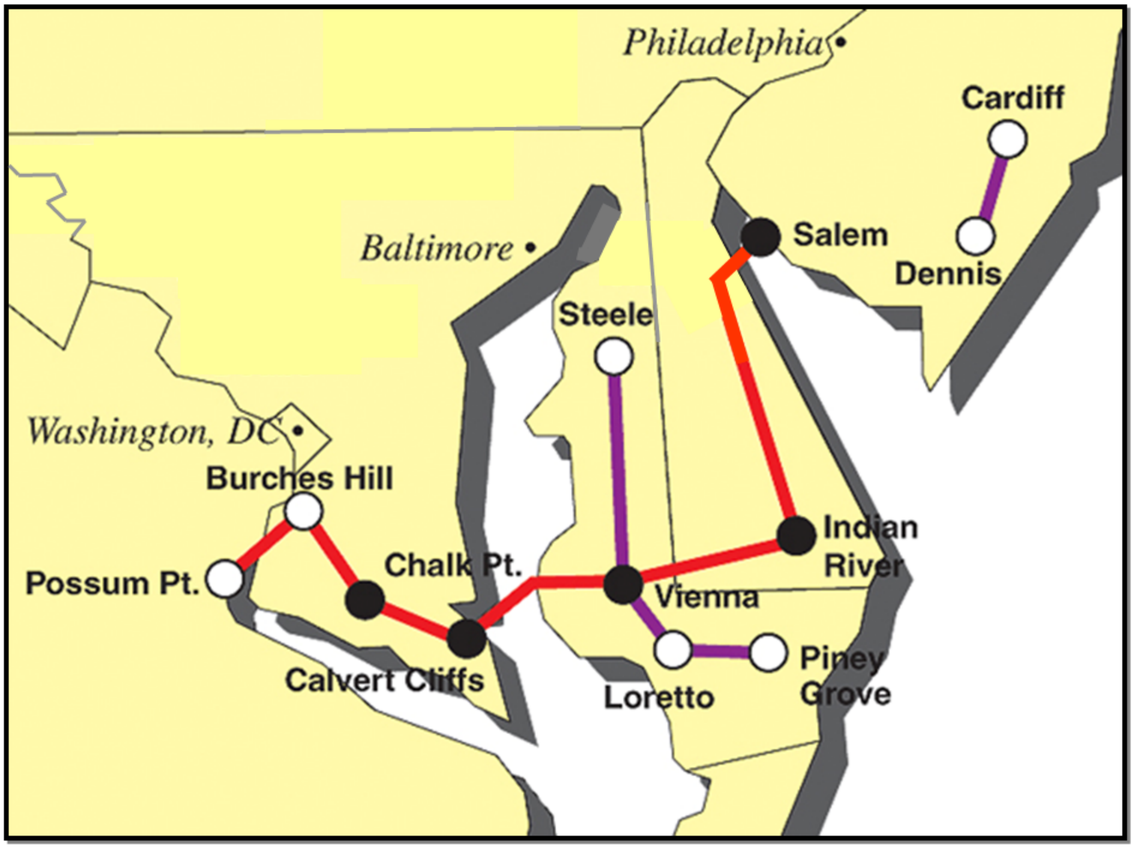
Delmarva Power's planners, which are then included in the PJM Regional Transmission Expansion Planning ("RTEP") process.

PJM's planning process is a rigorous process that is outlined in PJM Manual 14-B, available on the PJM web site. The planning process takes into account the requirement that the future transmission system meet all applicable reliability criteria including: North American Electricity Reliability Council ("NERC"), Reliability First Corporation, PJM and Delmarva local planning criteria. PJM tests the system under both expected normal peak conditions and extreme conditions where peak loads are higher than forecasted and there are more generating units out of service than would be expected under normal peak conditions. Based on this analysis, PJM with support from Delmarva, together develop a detailed 5 year plan to ensure that the transmission system has sufficient capability to serve the load. The transmission system plans that are developed include upgrades and additions to the transmission system as well as new reactive sources to assure that adequate transmission system voltages are maintained under all tested conditions. The table below provides a detailed listing of the individual transmission system upgrades that comprise the 5 year plan for Delmarva. A short description of each project as well as the PJM project ID#, expected in-service date and projected project cost are provided in the table. The information listed in the table is also available on the PJM web site.

Upgrade ID	Description	PJM Required In-Service Date	Cost Estimate ($M)
b0241.3	Red Lion Sub - 500/230kV work	6/1/2009	$12.630
b0261	Replace 1200 Amp disconnect switch on the Red Lion - Reybold 138kV circuit	6/1/2009	$0.075
b0262	Reconductor 0.5 mi of Christiana / Edgemoor 138kV line	6/1/2009	$0.175
b0263	Replace 1200 Amp wavetrap at Indian River on the Indian River - Frankford 138kV line	6/1/2010	$0.200
b0272.1	Replace line trap and disconnect switch at Keeney 500kV Sub - 5025 Line Terminal Upgrade	6/1/2010	$0.212
b0282	Install 46MVAR capacitors on the DPL distribution system	6/1/2009	$1.200
b0291	Replace 1600A disconnect switch at Harmony 230 kV and for the Harmony -Edgemoor 230kV circuit, increase the operating temperature of the conductor	6/1/2009	$0.850
b0295	Raise conductor temperature of North Seaford - Pine Street - Dupont Seaford 69kV	6/1/2009	$0.300
b0316	Upgrade Laurel - Mumford 69kV line operating temperature of 477 ACSR @ 125C to 140C	6/1/2009	$0.800
b0320	Create a new 230kV station that splits the 2nd Milford to Indian River 230kV line. Add a 230/69kV transformer and run a new 69kV line down to Harbeson 69kV	6/1/2010	$12.800
b0388	Hallwood/Parksley (6790-2) Upgrade	6/1/2009	$0.470
b0389	Indian River AT-1 and AT-2 138/69kV Replacements	6/1/2009	$5.211
b0414	Upgrade the Christiana - New Castle 138kV circuit	6/1/2009	$0.245
b0480	Rebuild Lank - Five Points 69 kV	6/1/2012	$3.400
b0481	Replace wave trap at Indian River 138kV on the Omar - Indian River 138kV circuit	6/1/2012	$0.200
b0482	Rebuild Millsboro - Zoar REA 69 kV	12/1/2008	$1.800
b0483	Replace Church 138/69 kV transformer and add two breakers	6/1/2009	$4.400
b0483.1	Build Oak Hall - Wattsville 138 kV line	6/1/2009	$2.700
b0483.2	Add 138/69 kV transformer at Wattsville	6/1/2009	$4.100
b0483.3	Establish 138 kV bus position at Oak Hall	6/1/2009	$1.200
b0484	Re-tension Worcester - Berlin 69 kV for 125 °C	6/1/2010	$0.200
b0485	Re-tension Taylor - North Seaford 69 kV for 125 °C	6/1/2010	$0.600
b0494.1	Install a 2nd Red Lion 230/138kV	6/1/2009	$2.523
b0494.2	Hares Corner - Relay Improvement	6/1/2009	$0.799
b0494.3	Reybold - Relay Improvement	6/1/2009	$0.165
b0494.4	New Castle - Relay Improvement	6/1/2009	$0.165
b0513	Maridel to Ocean Bay (6723-1) Rebuild	6/1/2012	$2.100
b0527	Bethany 69 kV - Add 30 MVAR of capacitors (Replace the existing 12 MVAR)	6/1/2010	$1.800
b0528	Bethany 138 kV - Add a 138/12kV transformer which will replace Bethany T1 69/12kV	6/1/2010	$4.900
b0529	Grasonville 69 kV - Add another 8.4 MVAR capacitor	6/1/2010	$1.300
b0530	Wye Mills 69 kV - Add 30 MVAR of capacitors (Replace the existing 12 MVAR)	6/1/2010	$1.800
b0531	Wye Mills 138 kV - Create a 4 breaker 138kV ring bus and add a 2nd Wye Mills 138/69kV transformer	6/1/2010	$6.000
b0566	Rebuild Trappe Tap – Todd 69 kV line	6/1/2010	$12.000
b0567	Rebuild Mt. Pleasant - Townsend 138 kV	6/1/2010	$3.920
b0568	Add third Indian River 230/138 kV transformer	6/1/2011	$7.300
TOI111	2nd 69kV Stevensville line	12/31/2008	$3.444
TOI115	Valley Road 138/12kV Substation	5/31/2014	$2.221
TOI133	Dupont Seaford to Laurel (6736) Upgrade Phase 2	6/1/2011	$2.516
TOI137	Loretto AT-1 and AT-2 138/69kV Replacements	6/1/2011	$2.800
TOI142	Vienna to Sharptown (6705) Rebuild	5/31/2013	$1.280
TOI143	Wye Mills - Establish a 138kV Ring Bus	6/1/2011	$1.850
TOI144	Church to Wye Mills - Establish a new 138kV Line	12/1/2014	$9.428
TOI147	Laurel to Short (6706) Rebuild	6/1/2013	$2.110
TOI148	Vienna to Nelson (13707) Rebuild	5/31/2014	$7.900
TOI158	Queenstown Sub - Establish 69/25 KV station	12/31/2011	$3.433
TOI159	Easton/Bozman -Convert 25KV to 69 KV	12/31/2009	$0.285
TOI164	Harmony-Add a 2nd 230/138 autotransformer	6/1/2012	$3.431
TOI240	Five Points/Lewes Tap (6751-3) - Rebuild	6/1/2012	$0.620
TOI242	Bridgeville/Greenwood (6738-1) - Upgrade	6/1/2013	$0.858
TOI244	Glasgow/Mt. Pleasant (13808-1) - Rebuild	12/31/2011	$5.080
TOI247	Church - Add a line position on the 138kV bus	12/1/2014	$0.715
TOI250	Cecil Sub - Add a 230/138kV autotransformer	12/31/2011	$4.923
TOI251	Delaney Sub - Removal	12/31/2008	$0.500
TOI352	Queenstown Sub - Transmission line for new sub	5/31/2009	$0.302
TOI354	Jacktown Sub - Install in-line switches	6/1/2008	$0.702
TOI355	Wye Mills / Easton (6707) - Convert to 138kV	6/1/2011	$1.039
TOI357	Darley / Silverside (6833) - Rebuild	12/31/2008	$0.987
TOI358	Easton - Create a 69kV bus position	12/31/2009	$0.931
TOI359	Bozman - Create a 69kV bus position	12/31/2009	$0.581

In addition to this 5 year detailed plan, PJM also develops a 15 year plan to determine the need for new major backbone transmission projects at 500 kV and above. This long term planning process has identified the need for a major 500 kV transmission upgrade which will serve the Delmarva Peninsula. This upgrade is the Mid-Atlantic Power Pathway ("MAPP"), shown in the diagram below. The 500kv portion of the MAPP project was approved by the PJM Board of Managers in October 2007. This project has a projected in-service date of 2013 and will provide additional reliability and economic benefits to the Delmarva Peninsula. Pepco Holdings, Inc. ("PHI") plans to implement this project in phases with certain of the segments targeted for 2011-2013 completion, which will result in benefits to the Delmarva Peninsula customers.

PHI/Delmarva has made significant progress towards meeting the projected in service date for the MAPP project. PHI/Delmarva has named the overall project manager and the remainder of the core team for this project to execute the siting, permitting and construction phases of the project. Initial design, siting, environmental and community outreach activities have begun. PHI expects to file a Certificate of Public Convenience and Necessity ("CPCN") application for the southern Maryland portion of the line by first quarter of 2009. PHI has worked with PJM to evaluate various technology options for crossing the Chesapeake Bay. At the October 15, 2008 Transmission Expansion Advisory Committee (TEAC) meeting PJM recommended that DC technology be used for the crossing of the Chesapeake Bay. This will increase transfer capability, allow greater controllability of flow on the line and have a smaller footprint in the Chesapeake Bay.



The line segment from the western shore of Maryland to the eastern shore of Maryland including the Chesapeake Bay Crossing is projected to be completed by 2013. PJM is still evaluating the need date for the section of the line from Indian River to Salem / Hope Creek. PHI will work with PJM to identify any short term transmission upgrades required to maintain the reliability of the transmission system until the full MAPP project is completed. The Company recently introduced a separate web site for the MAPP project at www.powerpathway.com. This web site will be an important link to our stakeholders going forward and a location where questions will be answered and updates posted.

2. Transmission Plans to Address Generation Retirement Scenarios

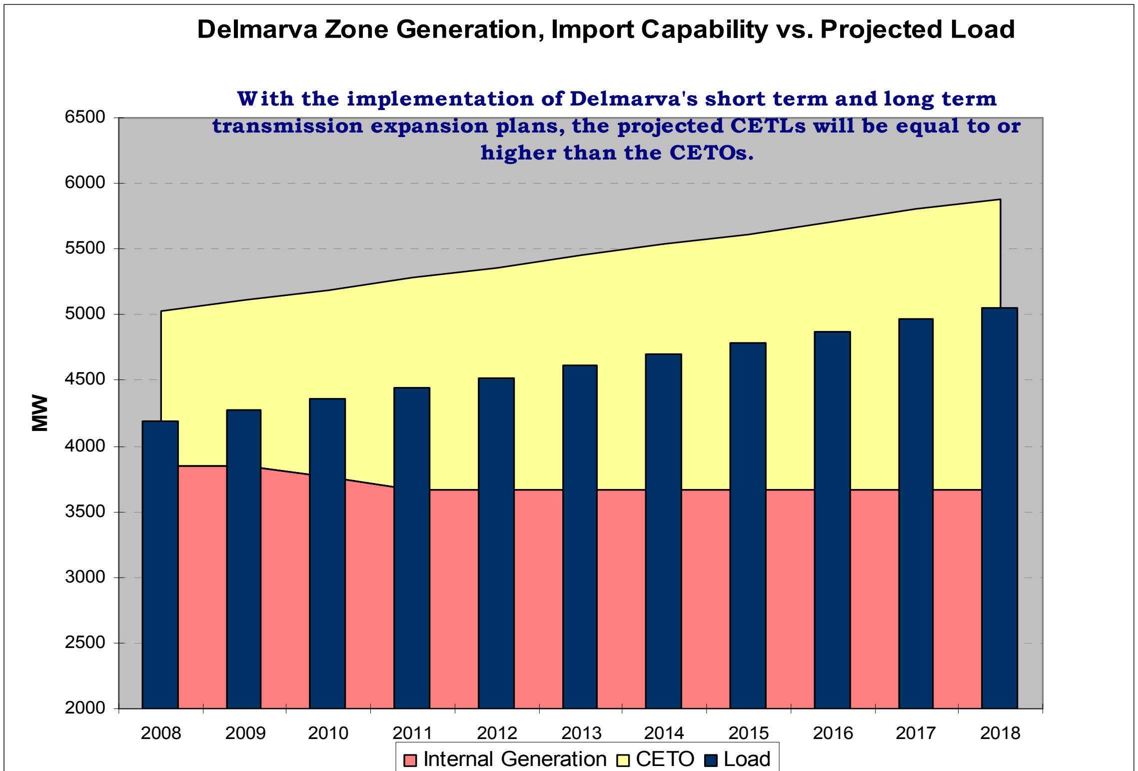
PJM's rules provide mechanisms to ensure reliability is addressed prior to any generation retirements. NRG has announced the planned retirement of the Indian River Unit #2 in May 2010 and Indian River Unit #1 in May 2011. PJM with support from Delmarva

Power has developed transmission plans to address these generation asset retirements and those plans were approved by the PJM Board in February 2008. The plans are based on the same rigorous PJM planning process used in the PJM base line to test the transmission system. The transmission enhancements necessary to maintain system reliability after the retirement of Indian River #1 and #2 are shown in the table below.

Retirement of Indian River #1 and #2

Recommanded Upgrades (Based on PJM CETO Analysis)	System Need Date	Estimated Cost ($MM)
Rebuild Mt. Pleasant to Townsend 138kV	Summer 2010	$3.9
Rebuild Trappe to Todd 69kV	Summer 2010	$12.0
Create a 138kV Ring Bus @ Wye Mills (w/ 2nd 138/69kV Transformer)	Summer 2010	$6.0
Add 30 MVAR 69kV Capacitor at Wye Mills	Summer 2010	$1.8
Add 8.4 MVAR 69kV Capacitor at Grasonville	Summer 2010	$1.3
Add 30 MVAR 69kV Capacitor at Bethany	Summer 2010	$1.8
Add a new 138/12kV Transformer at Bethany	Summer 2010	$4.9
Add a 3rd Indian River 230/138kV Transformer	Summer 2011	$7.3
Total Costs		**$39.0**

When considered on top of generation resources already existing within the PJM Delmarva Zone, the implementation of Delmarva's base reliability plan including the transmission investments identified above to be implemented prior to the scheduled retirements of Indian River Generating Units#1 and #2 will continue to maintain the established PJM regional reliability margins within the Zone. This is shown in the chart below:



Capacity Emergency Transfer Objective (CETO) - is the targeted import capability objective into the area to meet established regional reliability margins.
Capacity Emergency Transfer Limit (CETL) - is the estimated/calculated import capability into the area. For purposes of this graph, the projected CETLs are equal to or higher than the CETOs. The 2011/2012 CETL is calculated to be 1737MW. MAPP will add an additional 1000MW of import capability.

Sources: **Projected Load: PJM Load Forecast Report dated Jan 2008**

Generation Data: 2007 PJM Load, Capacity and Transmission Report dated July 25, 2007.
(Generation includes the retirements of Indian River #1 and #2. It does not include any potential future generation within the Delmarva Zone.)

In the event that other generation asset retirements are announced in the Delmarva Zone, PJM and Delmarva Power will develop the necessary transmission enhancement plans to ensure the continued reliable operation of the transmission system in the Zone. Delmarva Power has done a preliminary analysis to determine the upgrades that would be required if additional generation were to be retired. That preliminary analysis is shown in the table below.

Transmission Reinforcements	Retirement of Vienna 8 &10	Retirement of Edge Moor 3 & 4 and Vienna 8 &10	Retirement of Indian River 3 & 4 and Edge Moor 3 & 4 and Vienna 8 & 10	Estimated Cost ($MM)
Rebuild Glasgow to Mt. Pleasant 138kV	X	X	X	$5.7
Rebuild Easton to Trappe 69kV	X	X	X	$2.0
Add 25 MVAR 69kV Capacitor at Cool Springs		X	X	$1.5
Add 25 MVAR 69kV Capacitor at Church		X	X	$1.5
Add 30 MVAR 69kV Capacitor at Indian River			X	$1.5
Convert Vienna to Loretto to Piney Grove 138kV lines to 230kV			X	$24.0
Install a 230/138kV Transformer at Loretto and Vienna			X	$10.0
Add 2nd 230kV line from Steele to Vienna			X	$40.0

Notes:
1. Assumes the retirement of Indian River # 1 and # 2.
2. Includes all RTEP-approved plans (including MAPP 500kV).

The last three projects shown in the table are the 230 kV projects that compliment the MAPP project.

V. Solar Renewable Resources

Under the Delaware Renewable Portfolio Standard (RPS), Delmarva is required to obtain Renewable Energy Credits (RECs) in specified increasing percentage amounts from 2% in 2007 up to 19% in 2019. Delmarva plans to obtain most of the required RECs from the recently approved contracts with Bluewater Wind for off-shore wind resources and with AES and Synergics for land based wind resources. However, the Delaware RPS also specifies that a certain minimum number of RECs derived from solar photovoltaic resources need to be obtained in each year. These solar renewable energy credits (SREC's) are created for each MWH generated by solar energy resources. The table below shows the minimum cumulative percentage of RSCI SOS RPS requirements to be provided from solar photovoltaic resources:

Compliance Year (beginning June 1st)	Minimum Cumulative % from Solar Photovoltaics
2009	.014%
2010	.018%
2011	.048%
2012	.099%
2013	.201%
2014	.354%
2015	.559%
2016	.803%

2017	1.112%
2018	1.547%

Delmarva plans to undertake a multi-pronged approach to meeting the solar RPS requirements including 1) market purchases of (SREC's); 2) a longer term arrangement to purchase aggregated SREC's from the Delaware Sustainable Energy Utility (SEU); and 3).exploration of possible utility owned solar resources.

In the near term, prior to the establishment of the process by which the company can secure Specs through the SEU or the installation of any Company owned solar facilities, the purchase of solar renewable energy credits will come from the market through either the established SOS RFP bidding process as part of the full requirements service or through specific bids for this product.

A primary method to obtain Specs is expected to be through purchasing aggregated Specs from the SEU. The Company has met with the SEU and as a result, is expecting to obtain a recommendation from them as to the formula for purchasing these Specs on an ongoing basis. The formula would be an attempt to balance the need to provide a sustainable level of payment to encourage local solar generation over the long term while assuring that Delmarva's customers do not pay an unreasonable amount to meet the RPS solar requirements. It is expected that he SEU will provide the Company with a proposal in the first quarter of 2009. Based upon the Company's review and modification with the SEU as appropriate, Delmarva would then expect to file the SREC procurement plan with the Commission for approval no later than the second quarter of 2009. It is Delmarva's understanding that the SEU does not envision selling any aggregated Specs to the Company prior to the third quarter of 2009.

As of this filing, the effort to secure SRECs through Company owned facilities is still being developed. The Company is exploring different alternatives for owning solar resources to help meet the Delaware RPS.